Nos. 14-614 and 14-623

DEC - 8 2015

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

CPV MARYLAND, LLC, *Petitioner,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

JOINT APPENDIX VOLUME I

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*Counsel of Record

PETITIONS FOR WRIT OF CERTIORARI FILED: NOV. 25 & 26, 2014
CERTIORARI GRANTED: OCT. 19, 2015

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NOTICE

The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-614 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

Order No. 84815, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, 297 P.U.R.4th 336 (Md. Pub. Serv. Comm'n 2012) 29a

PPL EnergyPlus, LLC v. Nazarian, 974 F. Supp. 2d 790 (D. Md. 2013) (opinion) 62a

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PPL EnergyPlus, LLC v. Nazarian, Nos. 13-2419, 13-2424 (4th Cir. June 2, 2014) (judgment) 26a

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UNITED STATES DISTRICT COURT
DISTRICT OF MARYLAND (BALTIMORE)

CIVIL DOCKET FOR CASE #: 1:12-cv-01286-MJG

PPL ENERGYPLUS, LLC ET AL

V.

NAZARIAN ET AL

Date Filed: 04/27/2012
Date Terminated: 10/24/2013

Assigned to: Judge Marvin J. Garbis

Case in other court: Fourth Circuit Court of Appeals, 13-02419

Fourth Circuit Court of Appeals, 13-02424

Cause: 28:1331 Fed. Question: Bivens-Prisoner

Jury Demand: None

Nature of Suit: 950 Constitutional - State Statute

Jurisdiction: Federal Question

RELEVANT DOCKET ENTRIES

DATE	NO.	PROCEEDINGS
04/27/2012	1	COMPLAINT against DOUGLAS R. M. NAZARIAN, HAROLD WILLIAMS, LAWRENCE BRENNER,

DATE	NO.	PROCEEDINGS
		KELLY SPEAKES-BACKMAN, KEVIN HUGHES (Filing fee $ 350 receipt number 0416-3470790.), filed by PPL SUSQUEHANNA, LLC, PSEG POWER, LLC, PPL HOLTWOOD, LLC LOWER MOUNT BETHEL ENERGY, LLC, PPL NEW JERSEY BIOGAS, LLC, PPL BRUNNER ISLAND, LLC, ESSENTIAL POWER, LLC, PPL NEW JERSEY SOLAR, LLC, PPL ENERGYPLUS, LLC, PPL MARTINS CREEK, LLC, PPL RENEWABLE ENERGY, LLC, PPL MONTOUR, LLC. (Attachments: # 1 Civil Cover Sheet with Attachment, # 2 Summons, # 3 Summons, # 4 Summons, # 5 Summons, # 6 Summons)(Genth, Geoffrey) (Entered 04/27/2012)
	*	* * *
05/17/2012	8	Consent MOTION to Intervene by CPV Maryland, LLC Responses due by 6/4/2012 (Attachments: # 1 Memorandum in Support, # 2 Text of Proposed Order)(Hackett, Jennifer) (Entered: 05/17/2012)

DATE	NO.	PROCEEDINGS
05/17/2012	9	CERTIFICATE OF SERVICE by CPV Maryland, LLC re 8 Consent MOTION to Intervene (Hackett, Jennifer) (Entered: 05/17/2012)
	*	* * *
05/18/2012	20	ORDER granting 8 Motion of CVP Maryland, Inc. to Intervene. Signed by Judge Marvin J. Garbis on 5/18/2012. (bf2, Deputy Clerk) (Entered: 05/18/2012)
	*	* * *
05/29/2012	35	STIPULATION re 1 Complaint,, by CPV Maryland, LLC, Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Hackett, Jennifer) (Entered: 05/29/2012)
05/29/2012	36	MOTION to Dismiss by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams

DATE	NO.	PROCEEDINGS
		Responses due by 6/15/2012 (Davis, Ransom) (Entered: 05/29/2012)
05/29/2012	37	(FILED IN ERROR) MOTION to Dismiss by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 6/15/2012 (Davis, Ransom) Modified on 5/30/2012 (mps, Deputy Clerk). (Entered: 05/29/2012)
05/30/2012	38	QC NOTICE: 37 Motion to Dismiss filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian was filed incorrectly. ***The document is a Supporting Memorandum so it should not have been filed as a Motion. Please refile as a Memorandum. It has been noted as FILED IN ERROR, and the document link has been disabled.* (mps, Deputy Clerk) (Entered: 05/30/2012)
05/30/2012	39	Memorandum re 36 MOTION to Dismiss filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold

DATE	NO.	PROCEEDINGS
		Williams. (Davis, Ransom) (Entered: 05/30/2012)
05/31/2012	40	ORDER approving 35 Stipulation, filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Holtwood, LLC, PPL New Jersey Biogas, LLC, PSEG Power, LLC, PPL Martins Creek, LLC, CPV Maryland, LLC, PPL Renewable Energy, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL New Jersey Solar, LLC. Signed by Judge Marvin J. Garbis on 5/29/12. (mps, Deputy Clerk) (Entered: 05/31/2012)
	*	* * *
06/11/2012	42	Local Rule 103.3 Disclosure Statement by CPV Maryland, LLC identifying Corporate Parent Mitsubishi International Corporation, Corporate Parent Competitive Power Ventures Holdings, LLC, Corporate Parent CPV Maryland Holding Company, LLC, Corporate Parent CPV Power Development, Inc., Corporate Parent CPV Maryland Investment, LLC, Corporate

DATE	NO.	PROCEEDINGS
		Parent Warburg Pincus Private Equity IX, L.P., Corporate Parent Diamond St. Charles, LLC, Corporate Parent Diamond Generating Corporation, Corporate Parent Mitsubishi Corp. for CPV Maryland, LLC.. (Hackett, Jennifer) (Entered: 06/11/2012)
06/11/2012	43	MOTION to Dismiss for Failure to State a Claim by CPV Maryland, LLC Responses due by 6/28/2012 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3)(Hackett, Jennifer) (Entered: 06/11/2012)
	*	* * *
06/26/2012	46	MOTION for Other Relief To Participate as Amicus Curiae by Maryland Office of People's Counsel Responses due by 7/13/2012 (Attachments: # 1 Brief in Support of Motion, # 2 Affidavit Affidavit attached to brief, # 3 Text of Proposed Order, # 4 Certificate of Service)(Carmody, Paula) (Entered: 06/26/2012)
	*	* * *

DATE	NO.	PROCEEDINGS
06/28/2012	50	ORDER granting 46 Motion To Participate as Amicus Curiae. Signed by Judge Marvin J. Garbis on 6/28/12. (mps, Deputy Clerk) (Entered: 06/28/2012)
	*	* * *
07/03/2012	59	RESPONSE in Opposition re 36 MOTION to Dismiss, 43 MOTION to Dismiss for Failure to State a Claim filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by 7/20/2012. (Attachments: # 1 Supplement Attachment)(Bourgeois, John) (Entered: 07/03/2012)
	*	* * *
07/06/2012	62	STIPULATION Regarding Participation of Maryland Office of People's Counsel to Participate as Amicus Curiae by Essential Power, LLC, Lower Mount Bethel Energy, LLC,

DATE	NO.	PROCEEDINGS
		Maryland Office of People's Counsel, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Graham, Andrew) (Entered: 07/06/2012)
07/11/2012	63	ORDER approving 62 Stipulation, filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Holtwood, LLC, PPL New Jersey Biogas, LLC, PSEG Power, LLC, PPL Martins Creek, LLC, Maryland Office of People's Counsel, PPL Renewable Energy, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL New Jersey Solar, LLC. Signed by Judge Marvin J. Garbis on 7/10/12. (mps, Deputy Clerk) (Entered: 07/11/2012)
	*	* * *
07/25/2012	67	REPLY to Response to Motion re 43 MOTION to Dismiss for

DATE	NO.	PROCEEDINGS
		Failure to State a Claim filed by CPV Maryland, LLC. (Kleinman, Joel) (Entered: 07/25/2012)
07/25/2012	68	REPLY to Response to Motion re 36 MOTION to Dismiss filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Davis, Ransom) (Entered: 07/25/2012)
07/27/2012	69	Motion Hearing held on 7/27/2012 re 36 MOTION to Dismiss filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian, 43 MOTION to Dismiss for Failure to State a Claim filed by CPV Maryland, LLC before Judge Marvin J. Garbis - ARGUED, held subcuria. (CR: G. Simpkins) (CRD: bma) (Entered: 07/27/2012)
08/03/2012	71	MEMORANDUM AND ORDER denying 36 Motion to Dismiss; denying 43 Motion to Dismiss for Failure to State a Claim. Signed by Judge Marvin J. Garbis on 8/3/12. (mps, Deputy Clerk) (Entered: 08/06/2012)

DATE	NO.	PROCEEDINGS
08/05/2012	70	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 7-27-2012, before Judge Garbis. Court Reporter/Transcriber Gail Simpkins, Telephone number 410-962-4536. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 8/27/2012. Redacted Transcript Deadline set for 9/5/2012. Release of Transcript Restriction set for 11/5/2012. (gak, Court Reporter) (Entered: 08/05/2012)
08/08/2012	72	SECOND SCHEDULING ORDER. Signed by Judge Marvin J. Garbis on 8/7/12. (mps, Deputy Clerk) (Entered: 08/08/2012)
08/17/2012	73	ANSWER to 1 Complaint,, by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams.(Davis, Ransom) (Entered: 08/17/2012)

DATE	NO.	PROCEEDINGS
	*	* * *
08/24/2012	76	ANSWER to 1 Complaint,, by CPV Maryland, LLC.(Kleinman, Joel) (Entered: 08/24/2012)
	*	* * *
10/22/2012	81	MOTION for Protective Order Stipulated Discovery Confidentiality and Protective Order by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 11/8/2012 (Attachments: # 1 Exhibit A)(Genth, Geoffrey) (Entered: 10/22/2012)
10/31/2012	82	ORDER granting 81 Motion for Protective Order. Signed by Judge Marvin J. Garbis on 10/26/12. (mps, Deputy Clerk) (Entered: 11/01/2012)
	*	* * *
02/05/2013	103	MOTION to Dismiss Preemption Claims as Moot by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments:

DATE	NO.	PROCEEDINGS
		# 1 Memorandum of Points and Authorities, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Text of Proposed Order) (Kleinman, Joel) (Entered: 02/05/2013)
02/05/2013	104	MOTION in Limine by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 2/22/2013 (Attachments: # 1 Memorandum in Support, # 2 Text of Proposed Order)(Davis, Ransom) (Entered: 02/05/2013)
02/05/2013	105	MOTION in Limine to Exclude the Testimony of Roger Berliner by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum in Support, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3)(Genth, Geoffrey) (Entered: 02/05/2013)

DATE	NO.	PROCEEDINGS
02/05/2013	106	MOTION in Limine to Preclude Testimony Concerning Information Withheld by the Maryland PSC on a Claim ofDeliberative Process Privilege by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Law in Support, # 2 Exhibit 1, # 3 Exhibit 2, # 4 Exhibit 3, # 5 Exhibit 4, # 6 Exhibit 5, # 7 Exhibit 6, # 8 Exhibit 7, # 9 Exhibit 8)(Genth, Geoffrey) (Entered: 02/05/2013)
02/05/2013	107	MOTION in Limine to Preclude Testimony that Conflicts with the Findings of the Maryland PSC by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Appendix, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit, # 6 Exhibit, # 7 Exhibit, # 8 Exhibit, # 9

DATE	NO.	PROCEEDINGS
		Exhibit, # 10 Exhibit, # 11 Text of Proposed Order)(Broderick, Daniel) (Entered: 02/05/2013)
02/05/2013	108	MOTION in Limine to Preclude Legal Opinion Testimony of W L. Massey and to Strike Portions of his Expert Reports by CPV Maryland, LLC Responses due by 2/22/2013 (Attachments: # 1 Memorandum of Points and Authorities, # 2 Exhibit, # 3 Exhibit, # 4 Text of Proposed Order)(Broderick, Daniel) (Entered: 02/05/2013)
02/08/2013	109	RESPONSE in Opposition re 103 MOTION to Dismiss Preemption Claims as Moot – Plaintiffs' Opposition to Intervenor-Defendant CPV Maryland, LLC's Motion to Dismiss Preemption Claims as Moot filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by

DATE	NO.	PROCEEDINGS
		2/25/2013. (Attachments: # 1 Exhibit A)(Genth, Geoffrey) (Entered: 02/08/2013)
	*	* * *
02/11/2013	110	ORDER denying without prejudice 103 Motion to Dismiss Preemption Claims as Moot. Signed by Judge Marvin J. Garbis on 2/11/13. (mps, Deputy Clerk) (Entered: 02/12/2013)
02/12/2013	111	NOTICE by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams re 104 MOTION in Limine Notice of Filing ofLengthy Exhibit (Davis, Ransom) (Entered: 02/12/2013)
02/15/2013	112	RESPONSE to Motion re 107 MOTION in Limine to Preclude Testimony that Conflicts with the Findings of the Maryland PSC, 104 MOTION in Limine --- Response to PSC's Motion In Limine and CPV's Motion in Limine to Preclude Testimony That Conflicts with the Findings of the Maryland Public Service Commission filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL

DATE	NO.	PROCEEDINGS
		Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. Replies due by 3/4/2013. (Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	113	RESPONSE in Opposition re 108 MOTION in Limine to Preclude Legal Opinion Testimony of W L. Massey and to Strike Portions of his Expert Reports --- Memorandum in Opposition to Intervenor-Defendant CPV Maryland, LLC's Motion in Limine to Preclude Legal Opinion Testimony of William L. Massey and to Strike Particular Portions of Mr. Massey's Expert Reports filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG

DATE	NO.	PROCEEDINGS
		Power, LLC. Replies due by 3/4/2013. (Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	114	PRETRIAL MEMORANDUM by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	115	RESPONSE to Motion re 106 MOTION in Limine to Preclude Testimony Concerning Information Withheld by the Maryland PSC on a Claim of Deliberative Process Privilege Response to Motion in Limine re Deliberative Process Privilege filed by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 3/4/2013. (Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	116	RESPONSE to Motion re 105 MOTION in Limine to Exclude the Testimony of Roger Berliner Defendants' Joint Response to Motion in Limine re R. Berliner filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold

DATE	NO.	PROCEEDINGS
		Williams. Replies due by 3/4/2013. (Attachments: # 1 Exhibit, # 2 Exhibit)(Davis, Ransom) (Entered: 02/15/2013)
02/15/2013	117	TRIAL BRIEF by CPV Maryland, LLC. (Attachments: # 1 Appendix, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit, # 6 Exhibit, # 7 Exhibit, # 8 Exhibit, # 9 Exhibit)(Broderick, Daniel) (Entered: 02/15/2013)
02/15/2013	118	Proposed Pretrial Order submitted by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1 Attachment A, # 2 Attachment B)(Genth, Geoffrey) (Entered: 02/15/2013)
02/15/2013	119	SEALED PRETRIAL MEMORANDUM by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL

DATE	NO.	PROCEEDINGS
		Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Genth, Geoffrey) Modified on 2/16/2013 (cags, Deputy Clerk). (Entered: 02/15/2013)
02/15/2013	120	Interim MOTION to Seal Plaintiffs' Pretrial Memorandum by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 3/4/2013 (Genth, Geoffrey) (Entered: 02/15/2013)
02/19/2013	121	Supplemental to 117 Trial Brief filed by CPV Maryland, LLC . (Broderick, Daniel) (Entered: 02/19/2013)
02/20/2013	122	ORDER granting 120 Motion to Seal. Signed by Judge Marvin J. Garbis on 2/19/13. (mps, Deputy Clerk) (Entered: 02/20/2013)

DATE	NO.	PROCEEDINGS
	*	* * *
02/21/2013	125	ORDER re: pretrial motions. Signed by Judge Marvin J. Garbis on 2/21/13. (mps, Deputy Clerk) (Entered: 02/22/2013)
02/25/2013	126	Substantive legal issues - addressing (Attachments: # 1 Exhibit, # 2 Exhibit) (Broderick, Daniel) (Entered: 02/25/2013)
02/26/2013	127	MEMORANDUM AND ORDER granting in part 108 Motion in Limine. Signed by Judge Marvin J. Garbis on 2/25/13. (mps, Deputy Clerk) (Entered: 02/27/2013)
02/27/2013	128	Substantive legal issues - addressing (Genth, Geoffrey) (Entered: 02/27/2013)
03/04/2013	129	MOTION for Other Relief Proffer of Substantial Evidence by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams Responses due by 3/21/2013 (Davis, Ransom) (Entered: 03/04/2013)
03/04/2013	130	Bench Trial Day 1 begun on 3/4/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich AM / C. Asif PM) (pat,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 03/04/2013)
03/05/2013	131	Bench Trial Day 2 held on 3/5/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/06/2013)
03/06/2013	132	Bench Trial Day 3 held on 3/6/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/06/2013)
03/07/2013	133	Bench Trial Day 4 held on 3/7/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich AM / C. Asif PM) (pat, Deputy Clerk) (Entered: 03/07/2013)
03/08/2013	134	Bench Trial Day 5 held on 3/8/2013 before Judge Marvin J. Garbis. (Court Reporter: J. Sovich am / C. Asif pm) (pat, Deputy Clerk) (Entered: 03/08/2013)
03/11/2013	135	Bench Trial Day 6 held on 3/11/2013 before Judge Marvin J. Garbis. Closing arguments scheduled for April 16, 2013 at 10:00 AM. (Court Reporter: J. Sovich am / C. Asif pm) (pat,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 03/12/2013)
03/12/2013	136	Stipulation re: Return of exhibits to Counsel. (mps, Deputy Clerk) (Entered: 03/13/2013)
03/12/2013	137	ORDER sealing document. Signed by Judge Marvin J. Garbis on 3/4/13. (mps, Deputy Clerk) (Entered: 03/13/2013)
03/12/2013	138	Sealed Document. (mps, Deputy Clerk) (Entered: 03/13/2013)
	*	* * *
03/26/2013	140	TRIAL BRIEF by Maryland Office of People's Counsel. (Cleaver, Joseph) (Entered: 03/26/2013)
	*	* * *
03/26/2013	142	-SEALED- TRIAL BRIEF Plaintiffs' Post-Trial Brief by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1

DATE	NO.	PROCEEDINGS
		Appendix A)(Genth, Geoffrey) (Entered: 03/26/2013)
03/26/2013	143	MOTION to Seal Interim Sealing Motion by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC Responses due by 4/12/2013 (Genth, Geoffrey) (Entered: 03/26/2013)
03/26/2013	144	TRIAL BRIEF Plaintiffs'Post-Trial Brief (REDACTED) by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Attachments: # 1 Appendix A)(Genth, Geoffrey) (Entered: 03/26/2013)

* * * *

DATE	NO.	PROCEEDINGS
03/27/2013	147	TRIAL BRIEF by CPV Maryland, LLC. (Attachments: # 1 Exhibit, # 2 Exhibit, # 3 Exhibit, # 4 Exhibit, # 5 Exhibit)(Broderick, Daniel) (Entered: 03/27/2013)
03/27/2013	149	MARGINAL ORDER granting 143 Interim Motion to Seal. Signed by Judge Marvin J. Garbis on 3/27/13 (cags, Deputy Clerk) (Entered: 03/28/2013)
03/28/2013	148	STIPULATION to the accuracy of PSEG New Haven EQRs introduced by CPV Maryland, LLC. (Attachments: # 1 Exhibit, # 2 Exhibit)(Broderick, Daniel) (Entered: 03/28/2013)
04/01/2013	150	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-4-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013.

DATE	NO.	PROCEEDINGS
		Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(-css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	151	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-5-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(-css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	152	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-6-13, before Judge Garbis. Court Reporter/Transcriber Jacque-

DATE	NO.	PROCEEDINGS
		line Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	153	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-7-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline

DATE	NO.	PROCEEDINGS
		set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	154	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-8-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number 410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
04/01/2013	155	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3-11-13, before Judge Garbis. Court Reporter/Transcriber Jacqueline Sovich, Telephone number

DATE	NO.	PROCEEDINGS
		410 962 4537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 4/22/2013. Redacted Transcript Deadline set for 5/2/2013. Release of Transcript Restriction set for 7/1/2013. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 04/01/2013)
	*	* * *
04/05/2013	157	MOTION for Leave to File Statement of Interest by Robert F. Powelson Responses due by 4/22/2013 (Attachments: # 1 Exhibit A, # 2 Text of Proposed Order)(Curlett, Charles) (Entered: 04/05/2013)
04/05/2013	158	TRIAL BRIEF Reply by Maryland Office of People's Counsel. (Cleaver, Joseph) (Entered: 04/05/2013)
04/05/2013	159	RESPONSE re 158 Trial Brief filed by Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC,

DATE	NO.	PROCEEDINGS
		PPL Energyplus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC, PSEG Power, LLC. (Genth, Geoffrey) (Entered: 04/05/2013)
04/05/2013	160	RESPONSE re 142 Trial Brief, filed by CPV Maryland, LLC. (Broderick, Daniel) (Entered: 04/05/2013)
04/09/2013	161	RESPONSE in Opposition re 157 MOTION for Leave to File Statement of /nterest filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 4/26/2013. (Davis, Ransom) (Entered: 04/09/2013)
04/12/2013	162	REPLY to Response to Motion re 157 MOTION for Leave to File Statement of Interest filed by Robert F. Powelson. (Curlett, Charles) (Entered: 04/12/2013)
04/15/2013	163	ORDER denying 157 Motion for Leave to File Statement of Interest. Signed by Judge Marvin J. Garbis on 4/15/13.

DATE	NO.	PROCEEDINGS
		(dass, Deputy Clerk) (Entered: 04/15/2013)
04/16/2013	164	Oral Argument held on 4/16/2013 before Judge Marvin J. Garbis. (Court Reporter: Sovich) (rks, Deputy Clerk) (Entered: 04/17/2013)
	*	* * *
05/08/2013	170	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/4/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	171	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of

DATE	NO.	PROCEEDINGS
		Proceedings held on 3/5/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	172	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/6/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained

DATE	NO.	PROCEEDINGS
		from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	173	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/7/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	174	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/8/2013,

DATE	NO.	PROCEEDINGS
		before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
05/08/2013	175	NOTICE OF FILING OF OFFICIAL TRANSCRIPT of Proceedings held on 3/11/2013, before Judge Marvin J. Garbis. Court Reporter/Transcriber Christine T. Asif, Telephone number 410-962-4492. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or

DATE	NO.	PROCEEDINGS
		through PACER... Redaction Request due 5/29/2013. Redacted Transcript Deadline set for 6/10/2013. Release of Transcript Restriction set for 8/6/2013. (ca, Court Reporter) (Entered: 06/10/2013)
	*	* * *
09/30/2013	177	MEMORANDUM OF DECISION. Signed by Judge Marvin J. Garbis on 9/30/13. (mps, Deputy Clerk) (Entered: 09/30/2013)
	*	* * *
10/16/2013	182	Motion Hearing held on 10/16/2013 re 129 MOTION for Other Relief Proffer of Substantial Evidence filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian before Judge Marvin J. Garbis. (Court Reporter: J. Sovich) (pat, Deputy Clerk) (Entered: 10/16/2013)
	*	* * *
10/24/2013	187	JUDGMENT in favor of PPL Energyplus, LLC, et al against Douglas R. M. Nazarian, et al. Signed by Judge Marvin J. Garbis on 10/24/13. (mps,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 10/25/2013)
	*	* * *
11/21/2013	193	RESPONSE in Opposition re 190 Motion for Miscellaneous Relief, filed by Lawrence Brenner, CPV Maryland, LLC, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. Replies due by 12/9/2013. (Davis, Ransom) (Entered: 11/21/2013)
	*	* * *
11/22/2013	194	NOTICE OF APPEAL by Lawrence Brenner, Kevin Hughes, Douglas R. M. Nazarian, Kelly Speakes-Backman, Harold Williams. (Fee Status: Filing Fee Not Paid) (Davis, Ransom) Modified on 11/22/2013 (slss, Deputy Clerk). Modified on 11/25/2013 (sls, Deputy Clerk). (Entered: 11/22/2013)
11/22/2013	195	Transmission of Notice of Appeal and Docket Sheet to US Court of Appeals re 194 Notice of Appeal. IMPORTANT NOTICE: To access forms which you are required to file with the United States Court of Appeals

DATE	NO.	PROCEEDINGS
		for the Fourth Circuit please go to http://www.ca4.uscourts.gov and click on Forms & Notices. (slss, Deputy Clerk) (Entered: 11/22/2013)
	*	* * *
11/22/2013	197	NOTICE OF APPEAL by CPV Maryland, LLC. Filing fee $ 455, receipt number 0416-4446318. (Cross, David) Modified on 11/25/2013 (sls, Deputy Clerk). (Entered: 11/22/2013)
11/25/2013	198	Transmission of Notice of Appeal and Docket Sheet to US Court of Appeals re 197 Notice of Appeal. IMPORTANT NOTICE: To access forms which you are required to file with the United States Court of Appeals for the Fourth Circuit please go to http://www.ca4.uscourts.gov and click on Forms & Notices. (sls, Deputy Clerk) (Entered: 11/25/2013)
11/25/2013	199	USCA Case Number 13-2419 for 194 Notice of Appeal filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian - Case Manager - Brian Bain. (sls,

DATE	NO.	PROCEEDINGS
		Deputy Clerk) (Entered: 11/25/2013)
11/26/2013	200	USCA Case Number 13-2424 for 197 Notice of Appeal filed by CPV Maryland, LLC - Case Manager - Brian Bain. (slss, Deputy Clerk) (Entered: 11/26/2013)
11/27/2013	201	ORDER of USCA "CONSOLIDATING" USCA Case Nos. 13-2419(L) and 13-2424 as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 11/27/2013)
	*	* * *
12/11/2013	204	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 10-16-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber

DATE	NO.	PROCEEDINGS
		before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix)(~css, Court Reporter) (Entered: 12/11/2013)
12/11/2013	205	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 4-16-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for

DATE	NO.	PROCEEDINGS
		1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix) (~css, Court Reporter) (Entered: 12/11/2013)
12/11/2013	206	NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 2-21-13, before Judge Garbis, re 197 Notice of Appeal, 194 Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? – Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # 1 Appendix) (~css, Court Reporter) (Entered: 12/11/2013)
	*	* * *
06/02/2014	214	JUDGMENT of USCA (certified copy)"AFFIRMING" the judg-

DATE	NO.	PROCEEDINGS
		ment of the District Court as to 197 Notice of Appeal filed by CPV Maryland, LLC and 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/02/2014)
06/17/2014	215	STAY OF MANDATE of USCA as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/17/2014)
06/30/2014	216	ORDER of USCA "DENYING" petition for rehearing and rehearing en banc as to 197 Notice of Appeal filed by CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (sls, Deputy Clerk) (Entered: 06/30/2014)
07/08/2014	217	MANDATE of USCA issued as to 197 Notice of Appeal filed by

DATE	NO.	PROCEEDINGS
		CPV Maryland, LLC, 194 Notice of Appeal, filed by Lawrence Brenner, Harold Williams, Kelly Speakes-Backman, Kevin Hughes, Douglas R. M. Nazarian (ko, Deputy Clerk) (Entered: 07/08/2014)
07/25/2014	218	LIFT STAY ORDER. Signed by Judge Marvin J. Garbis on 7/25/14. (mps, Deputy Clerk) (Entered: 07/25/2014)
08/05/2014	219	Substantive legal issues - addressing (Davis, Ransom) (Entered: 08/05/2014)
08/05/2014	220	ORDER denying without prejudice 190 Motion for Costs; denying as moot 219 parties' joint request for a stay. Signed by Judge Marvin J. Garbis on 8/5/14. (mps, Deputy Clerk) (Entered: 08/05/2014)
10/20/2015	221	SUPREME COURT REMARK--petition for writ of certiorari granted.(bmhs, Deputy Clerk) (Entered: 10/21/2015)
10/20/2015	222	SUPREME COURT REMARK--petition for writ of certiorari granted. (bmhs, Deputy Clerk) (Entered: 10/21/2015)

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

Court of Appeals Docket #:13-2419

PPL ENERGYPLUS, LLC ET AL

v.

NAZARIAN ET AL

Docketed: 11/25/2013
Date Terminated: 06/02/2014

Nature of Suit: 3950 Constitutionality of State Statutes

Appeal From: United States District Court for the District of Maryland at Baltimore

Fee Status: fee paid

Case Type Information:
1) Civil Private
2) private
3) null

Originating Court Information:
District: 0416-1 : 1:12-cv-01286-MJG

Presiding Judge: Marvin J. Garbis, Senior U. S. District Court Judge

Date Filed: 04/27/2012
Date Order/Judgment: 10/24/2013
Date Order/Judgment EOD: 10/25/2013
Date NOA Filed: 11/22/2013
Date Rec'd COA: 11/22/2013

Prior Cases: None

Current Cases: Consolidated
Lead: 13-2419
Member: 13-2424
Start: 11/27/2013
End:

PPL ENERGYPLUS, LLC; PPL BRUNNER ISLAND, LLC; PPL HOLTWOOD, LLC; PPL MARTINS CREEK, LLC; PPL MONTOUR, LLC; PPL SUSQUEHANNA, LLC; LOWER MOUNT BETHEL ENERGY, LLC; PPL NEW JERSEY SOLAR, LLC; PPL NEW JERSEY BIOGAS, LLC; *Plaintiffs Appellees*

v.

DOUGLAS PPL RENEWABLE ENERGY, LLC; PSEG POWER LLC; ESSENTIAL POWER, LLC

R.M. NAZARIAN; HAROLD WILLIAMS; LAWRENCE BRENNER; KELLY SPEAKES-BACKMAN; KEVIN HUGHES

Defendants - Appellants

and

CPV MARYLAND, LLC

Defendant

AMERICAN PUBLIC POWER ASSOCIATION; NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; NRG ENERGY INC.; MARYLAND OFFICE OF PEOPLE'S COUNSEL; CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY; CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION; GEORGE JEPSEN, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT; CONNECTICUT OFFICE OF CONSUMER COUNSEL; NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, INC.; MAINE PUBLIC UTILITIES COMMISSION; RHODE ISLAND PUBLIC

UTILITIES COMMISSION; VERMONT PUBLIC SERVICE BOARD; VERMONT DEPARTMENT OF PUBLIC SERVICE; CALIFORNIA PUBLIC UTILITIES COMMISSION; PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK (NYPSC); PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA; DELAWARE PUBLIC SERVICE COMMISSION; NEW JERSEY BOARD OF PUBLIC UTILITIES; NEW JERSEY DIVISION OF RATE COUNSEL; MARYLAND ENERGY ADMINISTRATION; AMERICAN WIND ENERGY ASSOCIATION; THE MID-ATLANTIC RENEWABLE ENERGY COALITION

Amici Supporting Appellant

PJM POWER PROVIDERS GROUP; ELECTRIC POWER SUPPLY ASSOCIATION; EDISON ELECTRIC INSTITUTE

Amici Supporting Appellee

RELEVANT DOCKET ENTRIES

DATE	NO.	PROCEEDINGS
11/25/2013	1	Case docketed. Originating case number: 1:12-cv-01286-MJG. Case manager: Brian Bain. [13-2419] (BB)
11/27/2013	2	DOCKETING NOTICE issued Re: [1] case docketed Initial forms due within 14 days. Originating case number: 1:12-cv-01286-MJG.. [13-2419] (BB)
11/27/2013	4	ORDER filed [999248752] consolidating case 13-2424 with 13-2419.. Copies to all parties.. [13-2419, 13-2424] (BB)

* * * *

DATE	NO.	PROCEEDINGS
12/09/2013	7	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellees Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC and PPL Susquehanna, LLC. Was any question on Disclosure Form answered yes? Yes [999255565] [13-2419] Paul Clement
12/09/2013	8	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee Essential Power, LLC. Was any question on Disclosure Form answered yes? No [999255570] [13-2419] Paul Clement
12/09/2013	9	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee PSEG Power LLC. Was any question on Disclosure Form answered yes? Yes [999255572] [13-2419] Paul Clement
12/09/2013	10	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellees Lower

		Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC and PPL Susquehanna, LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? Yes [999255577] [13-2424, 13-2419] Paul Clement
12/09/2013	11	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee Essential Power, LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? No [999255578] [13-2424, 13-2419] Paul Clement
12/09/2013	12	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellee PSEG Power LLC in 13-2424, 13-2419. Was any question on Disclosure Form answered yes? Yes [999255580] [13-2424, 13-2419] Paul Clement
	* * * *	
12/11/2013	15	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for

		dates of 10-16-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # (1) Appendix)[13-2419, 13-2424] (JB)
12/11/2013	16	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 4-16-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline

		for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for 3/11/2014. (Attachments: # (1) Appendix[13-2419, 13-2424] (JB)
12/11/2013	17	DISTRICT COURT UPDATE. NOTICE OF FILING OF OFFICIAL TRANSCRIPT for dates of 2-21-13, before Judge Garbis, re [197] Notice of Appeal, [194] Notice of Appeal, Court Reporter/Transcriber Jacqueline Sovich, Telephone number 4109624537. Transcript may be viewed at the court public terminal or purchased through the Court Reporter/ Transcriber before the deadline for Release of Transcript Restriction. After that date it may be obtained from the Court Reporter or through PACER. Does this satisfy all appellate orders for this reporter? - Y. Redaction Request due 1/2/2014. Redacted Transcript Deadline set for 1/13/2014. Release of Transcript Restriction set for

		3/11/2014. (Attachments: # (1) Appendix[13-2419, 13-2424] (JB)
12/11/2013	18	DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Appellant CPV Maryland, LLC in 13-2424. Was any question on Disclosure Form answered yes? Yes [999257387] [13-2419, 13-2424] David Cross
	* * * *	
02/04/2014	35	FULL ELECTRONIC APPENDIX and full paper appendix by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419, Appellant CPV Maryland, LLC in 13-2424. Method of Filing Paper Copies: mail. Date paper copies mailed dispatched or delivered to court: 02/04/2014. Has district court 90-day restriction expired for all transcripts included in appendix? Yes. The electronic appendix is initially restricted to case participants only Case participants must be logged into CM/ECF to view the appendix prior to public release. Appendices in Immigration and Social Security cases will remain restricted.[999290440]

		[13-2419, 13-2424] Larry Eisenstat
02/04/2014	36	BRIEF by Appellant CPV Maryland, LLC in 13-2424 in electronic and paper format. Type of Brief: Opening. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/04/2014. [999290994] [13-2419, 13-2424] Larry Eisenstat
02/04/2014	37	BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Opening. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/04/2014. [999291085] [13-2419, 13-2424] Scott Strauss
02/04/2014	38	OPENING BRIEF (PAPER) file-stamped, on behalf of CPV Maryland, LLC in 13-2424. Number of pages: [50]. Sufficient: YES. Entered on Docket Date: 02/05/2014. [999291874] [13-2419, 13-2424] (BB)
02/04/2014	39	APPENDIX (PAPER) file-stamped, on behalf of Lawrence

		Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419, CPV Maryland, LLC in 13-2424. Total number of volumes (including any sealed): 6. Total number of pages in all volumes: 2091. Total number of sealed volumes: 0. Sufficient? Yes. Entered on Docket Date: 02/07/2014. [999293275] [13-2419, 13-2424] (BB)
02/04/2014	40	OPENING BRIEF (PAPER) file-stamped, on behalf of the Maryland Public Service Commission through Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Number of pages: [45]. Sufficient: YES. Entered on Docket Date: 02/07/2014. [999293476] [13-2419, 13-2424] (BB)
02/11/2014	41	AMICUS CURIAE/INTERVENOR BRIEF by Amici Curiae American Public Power Association and National Rural Electric Cooperative Association in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or

		Delivered to Court: 02/11/2014. [999295273] [13-2419, 13-2424] Randolph Elliott
02/11/2014	42	AMICUS CURIAE/INTERVENOR BRIEF by NRG Energy, Inc. in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295330] [13-2419, 13-2424] Jeffrey Lamken
02/11/2014	43	AMICUS CURIAE/INTERVENOR BRIEF by American Wind Energy Association and The Mid-Atlantic Renewable Energy Coalition in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295832] [13-2424, 13-2419] Eugene Grace
02/11/2014	44	AMICUS CURIAE/INTERVENOR BRIEF by Maryland Office of People's Counsel, Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: courier. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295873]

		[13-2419, 13-2424] William Fields
02/11/2014	45	AMICUS CURIAE/INTERVENOR BRIEF by Amici Curiae the Connecticut Public Utilities Regulatory Authority, et al. in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/11/2014. [999295982] [13-2419, 13-2424] Susanna Chu
02/11/2014	46	AMICUS CURIAE/INTERVENOR BRIEF by Maryland Energy Administration as Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 02/12/2014. [999295987] [13-2419, 13-2424] Steven Talson
02/11/2014	47	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of APPA and NRECA in 13-2419. Number of pages: [41]. Entered on Docket Date: 02/14/2014.[999296869] [13-2419, 13-2424] (BB)
02/11/2014	48	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of NRG Energy Inc. in 13-2419.

		Number of pages: [44]. Entered on Docket Date: 02/14/2014.[999296870] [13-2419, 13-2424] (BB)
02/11/2014	49	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of Maryland Office of People's Counsel in 13-2419. Number of pages: [37]. Entered on Docket Date: 02/14/2014.[999296871] [13-2419, 13-2424] (BB)
02/11/2014	50	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of California Public Utilities Commission, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Connecticut Public Utilities Regulatory Authority, Delaware Public Service Commission, George Jepsen, Maine Public Utilities Commission, New England Conference of Public Utilities Commissioners, Inc., New Jersey Board of Public Utilities, New Jersey Division of Rate Counsel, Public Service Commission of the District of Columbia, Public Service Commission of the State of New York (NYPSC), Rhode Island Public Utilities Commission, Vermont Department of Public

		Service and Vermont Public Service Board in 13-2419. Number of pages: [44]. Entered on Docket Date: 02/14/2014.[999296872] [13-2419, 13-2424] (BB)
02/11/2014	58	MOTION (re-docketed by clerk) by Potential Amicus Curiaes AWEA and The Mid-Atlantic Renewable Energy Coalition in 13-2419 to file amicus curiae brief (FRAP 29(e)) without consent of all parties on appeal within time allowed by FRAP 29(e).. Date and method of service: 02/11/2014 ecf. [999303487] [13-2419, 13-2424] (BB)
02/11/2014	60	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of Maryland Energy Administration in 13-2419, 13-2424. Number of pages: [12]. Entered on Docket Date: 02/25/2014.[999303533] [13-2419, 13-2424] (BB)
02/11/2014	63	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of AWEA and The Mid-Atlantic Renewable Energy Coalition in 13-2419, 13-2424. Number of pages: [11]. Entered on Docket Date: 03/03/2014. [999307150] [13-2419, 13-2424] (BB)

02/14/2014	52	NOTICE ISSUED to counsel requesting response to motion for leave to file an Amicus Curiae Brief [43] Response due: 02/21/2014.[999296937].. [13-2419, 13-2424] (BB)
02/18/2014	53	RESPONSE/ANSWER by CPV Maryland, LLC in 13-2424 to notice requesting response [52], amicus curiae Brief [43]. [13-2419, 13-2424] Clifton Elgarten
02/19/2014	54	RESPONSE/ANSWER by Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes Backman and Harold Williams in 13-2419 to notice requesting response [52], amicus curiae Brief [43]. [13-2419, 13-2424] Scott Strauss

* * * *

02/24/2014	57	Amended DISCLOSURE OF CORPORATE AFFILIATIONS (Local Rule 26.1) by Amicus Supporting Appellant NRG Energy Inc. in 13-2419, 13-2424. Was any question on Disclosure Form answered yes? [13-2419, 13-2424] Jeffrey Lamken
02/25/2014	59	ORDER filed [999303509] granting Motion to file amicus curiae brief [58] in 13-2419 Copies to all parties.. [13-2419, 13-2424] (BB)

* * * *

03/10/2014	65	BRIEF by Appellees Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424 in electronic and paper format. Type of Brief: Response. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/11/2014. [999312548] [13-2419, 13-2424] Paul Clement
03/10/2014	67	RESPONSE BRIEF (PAPER) file-stamped, on behalf of Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424. Number of pages: [87].

		Sufficient: YES. Entered on Docket Date: 03/13/2014. [999314937] [13-2419, 13-2424] (BB)
		* * * *
03/12/2014		Appendix [35] released to public. [13-2419, 13-2424] (BB)
03/17/2014	69	AMICUS CURIAE/INTERVENOR BRIEF by Ashley C. Parrish for Amicus Curiae Electric Power Supply Association in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/17/2014. [999317080] [13-2419, 13-2424] Ashley Parrish
03/17/2014	70	AMICUS CURIAE/INTERVENOR BRIEF by PJM Power Providers Group, Amicus Curiae in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 03/18/2014. [999317345] [13-2419, 13-2424] John Shepherd
03/17/2014	72	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of EEI and Electric Power Supply Association in 13-2419,

		13-2424. Number of pages: [51]. Entered on Docket Date: 03/19/2014.[999318928] [13-2419, 13-2424] (BB)
03/17/2014	73	AMICUS CURIAE BRIEF (PAPER) file-stamped, on behalf of PJM Power Providers Group in 13-2419, 13-2424. Number of pages: [44]. Entered on Docket Date: 03/19/2014.[999318933] [13-2419, 13-2424] (BB)
	* * * *	
04/03/2014	82	BRIEF by Appellant CPV Maryland, LLC in 13-2424 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 04/03/2014. [999330140] [13-2419, 13-2424] Larry Eisenstat
04/03/2014	83	(ENTRY RESTRICTED) BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to

		Court: 04/03/2014. [999330163] [13-2419, 13-2424] Scott Strauss
04/03/2014	84	REPLY BRIEF (PAPER) file-stamped, on behalf of CPV Maryland, LLC in 13-2424. Number of pages: [42]. Sufficient: YES. Entered on Docket Date: 04/04/2014. [999330497] [13-2419, 13-2424] (BB)
04/03/2014	85	REPLY BRIEF (PAPER) file-stamped, on behalf of Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Number of pages: [55]. Sufficient: YES. Entered on Docket Date: 04/04/2014. [999330539] [13-2419, 13-2424]--[Edited 04/07/2014 by BB] (BB)
04/04/2014	86	Errata sheet for paper briefs by Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. Identify brief: reply. Corrected electronic brief must be filed separately by counsel. [13-2419, 13-2424] Scott Strauss
04/04/2014	87	Corrected BRIEF by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-

		Backman and Harold Williams in 13-2419 in electronic and paper format. Type of Brief: Reply. Method of Filing Paper Copies: mail. Date Paper Copies Mailed, Dispatched, or Delivered to Court: 04/03/2014. [999330556] [13-2419, 13-2424] Scott Strauss
	* * * *	
04/11/2014	89	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) by Appellees Essential Power, LLC, Lower Mount Bethel Energy, LLC, PPL Brunner Island, LLC, PPL EnergyPlus, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL New Jersey Biogas, LLC, PPL New Jersey Solar, LLC, PPL Renewable Energy, LLC, PPL Susquehanna, LLC and PSEG Power LLC in 13-2419, 13-2424. [999335281]. [13-2419, 13-2424] Paul Clement
04/16/2014	90	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) response by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. [999338012]. [13-2419, 13-2424] Scott Strauss

* * * *

04/17/2014	92	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) response by Appellant CPV Maryland, LLC in 13-2424. [999338339]. [13-2419, 13-2424] Clifton Elgarten

* * * *

05/13/2014	95	ORAL ARGUMENT heard before the Honorable J. Harvie Wilkinson, III, Barbara Milano Keenan and Albert Diaz. Attorneys arguing case: Mr. Scott H. Strauss for Appellants Harold Williams, Lawrence Brenner, Douglas R.M. Nazarian, Kelly Speakes-Backman and Kevin Hughes, Mr. Paul D. Clement for Appellees PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PSEG Power LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, PPL Renewable Energy, LLC and Essential Power, LLC and Mr. Clifton Scott Elgarten for none CPV Maryland, LLC in 13-2419. Courtroom Deputy: Joy Moore.

		[999355292] [13-2419, 13-2424] (JHM)
05/29/2014	96	MOTION by Amici Supporting Appellant APPA and National Rural Electric Cooperative Association in 13-2419, 13-2424 for Leave to Substitute Cover for Brief. Date and method of service: 05/29/2014 ecf. [999365297] [13-2419, 13-2424] John Coyle
05/30/2014	97	ORDER filed [999366055] granting Motion to File a Corrected Cover [96] Copies to all parties.. [13-2419, 13-2424] (BB)
05/30/2014	98	SUPPLEMENTAL AUTHORITIES (FRAP 28(j)) by Appellant CPV Maryland, LLC in 13-2424. [999366448]. [13-2419, 13-2424] Clifton Elgarten
06/02/2014	99	PUBLISHED AUTHORED OPINION filed. Originating case number: 1:12-cv-01286-MJG. [999366884] Annootation added to opinion reflecting Supreme Court history--[Edited 11/05/2015 by SJC]. [13-2419, 13-2424] (BB)
06/02/2014	100	JUDGMENT ORDER filed. Disposition method: 13-2419 opn.p.arg 13-2424 opn.p.arg. Decision: Affirmed. Originating case number: 1:12-cv-01286-

		MJG. Entered on Docket Date: 06/02/2014. [999366889] Copies to all parties and the district court/agency.. [13-2419, 13-2424] (BB)
06/16/2014	101	PETITION for rehearing and rehearing en banc by Appellants Lawrence Brenner, Kevin Hughes, Douglas R.M. Nazarian, Kelly Speakes-Backman and Harold Williams in 13-2419. [13-2419, 13-2424] Scott Strauss
06/16/2014	102	PETITION for rehearing and rehearing en banc by Appellant CPV Maryland, LLC in 13-2424. [13-2419, 13-2424] Larry Eisenstat
06/17/2014	103	Mandate stayed by FRAP 41(d)(1).. [13-2419, 13-2424] (DL)
06/23/2014	104	(ENTRY RESTRICTED) AMICUS CURIAE/INTER-VENOR BRIEF by Amicus Supporting Appellant AWEA in 13-2419 in electronic and paper format. Type of Brief: Amicus Curiae. Method of Filing Paper Copies: mail. [999381585] [13-2419, 13-2424] Eugene Grace
06/24/2014	105	COURT ORDER filed [999382623] denying amicus curiae Brief [104] in 13-2419; denying granting filing of

		amicus curiae brief (FRAP 29(e)) Copies to all parties.. [13-2419, 13-2424] (BB)
06/30/2014	106	COURT ORDER filed [999386329] denying Motion for rehearing and rehearing en banc [102], denying Motion for rehearing and rehearing en banc [101] Copies to all parties.. [13-2419, 13-2424] (BB)
07/08/2014	107	Mandate issued. Referencing: [100] Judgment Order, [99] Published Authored Opinion. Originating case number: 1:12-cv-01286-MJG.. [13-2419, 13-2424] (BB)
09/19/2014	108	SUPREME COURT REMARK--extension granted to file petition for writ of certiorari. Petition for certiorari now due: November 27, 2014. [13-2419, 13-2424] (ABW)
	* * * *	
11/30/2014	110	SUPREME COURT REMARK--petition for writ of certiorari filed. 11/25/2014. 14-614. [13-2419, 13-2424] (SJC)
12/01/2014	111	SUPREME COURT REMARK--petition for writ of certiorari filed. 11/26/2014. 14-623. [13-2419, 13-2424] (SJC)
	* * * *	

10/20/2015	113	SUPREME COURT REMARK--petition for writ of certiorari granted. 10/19/2015 [13-2419, 13-2424] (SJC)
10/20/2015	114	SUPREME COURT REMARK--petition for writ of certiorari granted. 10/19/2015 [13-2424, 13-2419] (SJC)

135 FERC ¶ 61,022 (Exh. D234)
FEDERAL ENERGY REGULATORY COMISSION
WASHINGTON, D.C. 20426

Docket No. ER11-2875-000
Docket No. EL11-20-000

PJM INTERCONNECTION, L.L.C.
PJM POWER PROVIDERS GROUP

v.

PJM INTERCONNECTION, L.L.C.

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

(Unconsolidated)

ORDER ACCEPTING PROPOSED TARIFF REVISIONS, SUBJECT TO CONDITIONS, AND ADDRESSING RELATED COMPLAINT

(Issued April 12, 2011)

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Appendix

120. PJM notes that the Commission rejected a proposal to replace the current MOPR with a provision that would have given responsibility to the IMM to determine whether a seller's new entry offer was an exercise of market power. [65] The Commission did not, however, object to the IMM participating in the process of making this determination. Instead, the Commission objected to a proposal that would have given the IMM "unfettered discretion" to make such determinations unilaterally through a process that would have lacked the certainty for market participants that more objective MOPR tariff standards could provide. [66] The procedure proposed by the IMM and accepted here does not give the IMM the discretion to unilaterally decide whether a resource gets mitigated. We therefore find that the IMM's proposal is consistent with our precedent.

121. We find that first having the opportunity to justify offers with the IMM, and then with PJM, will allow for a less burdensome process than the one proposed by PJM for cost justification purposes. We therefore direct PJM to file, within 30 days of the date of this order, a compliance filing containing revisions to its tariff that allow for a process in which a market participant may first submit its proposed offer with full documentation to the IMM for review. The process must also allow the market participant to have the opportunity to receive a determination from PJM if the IMM's findings are adverse to its interests. To provide certainty to market participants, we will further require these proposed tariff provisions to include an

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[65] PJM Filing at 13 (citing March 26 Order, 126 FERC 61,275 at P 190.

[66] *Id.*

explanation of the information resources that will need to be submitted to the IMM for this determination and the objective standards by which such submittals will be evaluated.

122. In conducting an individualized generation review, PJM proposes that: a sell offer would be permissible when such offer is consistent with the competitive, cost-based, fixed, nominal levelized, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. We find that this standard is appropriate for reviewing such cost estimates and that PJM must include this language in its revised tariff.

123. Finally, we find P3's "No-Subsidy" Off-Ramp proposal unnecessary. All parties have the opportunity to avoid mitigation by making a cost demonstration, and we are not persuaded that adding an additional exemption is warranted.

G. State Mandated Exemption

124. The MOPR exempts from its operation any planned resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation and an opportunity to be heard.[67]

1. PJM's Proposal

125. PJM proposes to make MOPR exceptions based on state policy grounds subject to the same process as any other sell offer seeking a MOPR exception, i.e., subject to the receipt of a section 206 authorization.

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[67] PJM OATT, Attachment DD, Section 5.14(h)(l)(iv).

PJM states that this policy would be consistent with the policy that the Commission has required the NYISO to adopt.[68] PJM's proposed language provides an exemption for new entry that is pursuant to "a state-mandated requirement that furthers a specific legitimate state objective" and that involves a sell offer that would not "lead to artificially depressed capacity prices" or "directly and adversely impact [the Commission's] ability to set just and reasonable rates for capacity sales" in the PJM region or any affected locational deliverability area.

126. In support of its proposal, PJM notes that the existing rule requires it to pass on the adequacy of state administrative processes and to determine whether an offer is legitimately intended to address a projected capacity shortfall. PJM asserts that an RTO is not well-suited to do either.

2. P3's Proposal

127. P3 asserts that PJM's existing state mandate exemption is inadequate for the purposes of deterring buyer market power because it allows states to shield schemes intended to promote uncompetitive sell offers. P3 argues that there should be no separate exemption for state-sponsored generation projects.

3. Responsive Pleadings

128. Dominion, Viridity and CPV Power argue that the language of the current MOPR state-exemption should be retained. Viridity argues that changing this longstanding rule that specifically protects the ability of NJ and MD to do exactly what they have proposed would have the effect of propping up prices in the capacity market - at the same time that evidence

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[68] *See* NYISO Mitigation Order, 122 FERC 61,211 at P 92.

suggests that the RPM market construct should be eliminated or substantially modified. According to CPV Power, the current MOPR exemption for state-sponsored projects is precisely the mechanism developed through the stakeholder process pursuant to which a state could go outside of the RPM auctions when it believed they were failing to generate resources the state determined to be necessary.

129. On the other hand, PPL objects to the current MOPR's exemption for state- sponsored projects, arguing that no party should be granted *carte blanche* to exercise market power.

130. Among the parties who support PJM's proposal to permit a below-cost offer to escape mitigation if the seller first obtains a determination from the Commission under section 206 is the Pennsylvania Commission, which argues that this approach achieves the correct balance of protecting the RPM against buyer market power while respecting states' rights to develop individual energy policies tailored to their state. Moreover, argues the Pennsylvania Commission, PJM's solution is more reasonable than the proposal submitted by P3, which unnecessarily requires PJM to determine whether a resource has received any improper subsidies or is bidding at cost. The Pennsylvania Commission agrees with PJM that when necessary, review of state policy justifications is a matter better addressed by the Commission than by PJM, and asserts that this also ensures a more transparent process.

131. Shell also supports PJM' s proposal, stating that states other than New Jersey and Maryland are acting to suppress RPM clearing prices by, for example, using non- bypassable retail rates to subsidize new capacity that is offered into the RPM auctions at below-competitive prices guaranteed to clear. Hess

supports PJM's proposal to the extent it requires a project seeking a state-policy exemption to file with the Commission under section 206, but requests that the Commission direct PJM to submit a compliance filing to make clear that states seeking an exemption on state policy grounds must only seek such an exemption with respect to projects that are unable to pass the economic entry test (which Hess argues should be based on unit-specific net CONE).

132. Among the parties who object to PJM's proposal are those who object to the requirement that the filing be made under section 206, as opposed to a simple petition or motion, or a section 205 filing.[69] According to the PJM Load Group, it is not clear what a seller must prove to be unjust and unreasonable under a section 206 filing. PJM Load Group and the New Jersey Rate Counsel assert that the procedural vehicle should instead be a section 205 filing (for those entities entitled to make such filings) or a petition for declaratory order (for those entities like municipal and cooperative customers that are not entitled to do so). The PJM Load Group further argues that the filing fee for such a petition for declaratory order must be set at the same level as a section 205 filing, that is, zero.

133. Dominion and the Maryland Commission are concerned about timing under PJM's proposal. The Maryland Commission notes that a new resource would be required to submit its section 206 petition substantially in advance of the auction and that an incumbent generator intent on litigation could forestall the Commission's acting on the petition before the auction, erecting yet another barrier to

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[69] These parties include Dominion, the PJM Load Group, and New Jersey Rate Counsel.

entry. Dominion notes that because a Commission determination must be made prior to the auction, it will be impossible for the Commission to determine whether or not the offer at issue will affect market-clearing prices.

134. Other parties object to the language of PJM's proposed state-policy exemption. The PJM Load Group maintains that PJM's proposed language improperly attempts to limit the circumstances in which the Commission may find that a screened offer is just and reasonable and suffers from circular reasoning.[70] According to the PJM Load Group, if PJM's proposed MOPR changes are intended to prevent "artificially depressed capacity prices" and to prevent "unjust and unreasonable rates for capacity sales," then PJM is essentially taking the position that a screened offer may be unscreened only if it passes the screen. The New Jersey Rate Counsel and the Maryland Commission have a similar concern: if all downward price pressures are considered "artificial" price suppression, then PJM's new proposed criterion would swallow the exemption. The New Jersey Rate Counsel believes that the existing MOPR reliability-based exception should be retained, with the only change being the

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[70] As noted in the prior section, to rectify this and the PJM Load Group's above- mentioned procedural concern, PJM Load Group proposes that "If the Commission does require that screen clearances be obtained from the Commission, then at least PJM's proposed Section 5.14(h)(5) should be modified by deleting the words '206 of the FPA' and inserting in lieu thereof the words '205 of the FPA or a petition for a declaratory order.' Also, to eliminate PJM's proposed, inherently circular constraints on the Commission's discretion, a period should be placed after the word 'permissible' in proposed Section 5.14(h)(5) and the remainder of the section should be deleted." See the PJM Load Group Protest at 65.

Commission would determine whether the exemption had been met.

135. The Maryland Commission further argues that PJM's proposal introduces unnecessary bureaucratic process, raises new regulatory obstacles and costs for new entrants, and places the Commission in the position of second-guessing state policies and actions.[71] CPV Power similarly asserts that limiting the state's prerogatives only to projects that the Commission approves pursuant to a section 206 filing would establish the Commission as arbiter of decisions expressly left to states by the FPA. CPV Power submits that all state-mandated projects should be assumed to promote legitimate public policies and therefore should be exempt from mitigation, unless the IMM or other party can show that the project resulted from a state-mandated process intended solely to suppress wholesale capacity prices, and requests that the Commission modify PJM's proposal to this end.

136. On the other hand, a number of commenters agree with P3 that the state-policy exemption should be eliminated altogether. EPGA asserts that state-supported generation initiatives in New Jersey and Maryland threaten the efficacy of the capacity market and that, absent changes, there will be an artificial suppression in the capacity market and proper signals will not promote investment for new or incremental generation. EPGA argues that existing capacity resources will be financially harmed, consumers will not be aided in their consumption decisions, and

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[71] Maryland Commission protest, Exhibit 1, Nazarian Testimony at 19-20.

demand response and other load management programs will be compromised. Finally, EPGA argues that other states may need to seek ratepayer subsidies in order to build generation. A number of commenters, including Compete and FirstEnergy, argue that the MOPR should be adjusted to require full mitigation, that is, to require that generation capacity resources that receive ratepayer- funded out-of-market payments under state commission-approved programs or orders must offer all such capacity into the RPM at an offer price that is equal to 100 percent of their costs or of net CONE.[72]

137 Several parties, including the Pennsylvania Commission, the IMM and EPSA, note that states seeking full independence in resource procurement choices can opt out of the RPM markets via the Fixed Resource Requirement (FRR) alternative[73] or can implement a form of capacity procurement that complements the RPM. According to the Pennsylvania Commission, under the FRR alternative, a state undertakes to bear all of the costs and receive all of the benefits associated with procuring all necessary capacity resources for its citizens. This, according to

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[72] The IMM also proposes that out of market payments not be permitted. *See* IMM comments at 13.

[73] *See* PJM Reliability Assurance Agreement at Schedule 8.1. An entity that chooses the FRR alternative submits an FRR capacity plan to PJM, a long-term plan for the commitment of capacity resources to satisfy the entity's capacity obligations. The area covered by the plan is: (i) the service territory of an IOU; (ii) the service area of a public power entity or electric cooperative; or (iii) a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, and for which the FRR entity has or assumes the obligation to provide capacity for all load (including load growth) within such area.

the Pennsylvania Commission, contrasts sharply with the problem posed by unmitigated subsidized entry, where the costs are borne not only by consumers within the state that is sponsoring the entry, but also by other states within PJM. In the case of unmitigated subsidized entry, the Pennsylvania Commission asserts that one state's choice to subsidize resources will completely undermine competitive markets for resources serving other states, including resources in those states that prefer to rely on private capacity for generation construction.[74] The Pennsylvania Commission asserts that no one state (or states) can claim the right to artificially skew wholesale outcomes by escaping market power mitigation of subsidies, particularly given that such efforts would affect all other PJM states.

138. Finally, the Ohio Commission requests that the Commission affirm that individual states possess and will continue to possess the requisite authority to require the construction of generation facilities within the confines of their respective state boundaries. In addition, the Ohio Commission requests that the Commission affirm that states will continue to possess the requisite authority to arrive at the proper intrastate cost recovery mechanism for that generation. In addition, the Ohio Commission maintains that the Commission must affirm that individual states are not precluded from ensuring that electric distribution utilities can dedicate to intrastate consumers the

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[74] Pennsylvania Commission comments at 13 ("Pennsylvania is committed to the competitive market structure and would be harmed by any action by another state within PJM that subsidized a participant in PJM's interstate wholesale electric capacity market, absent an effective mitigation mechanism in PJM's RPM").

capacity and energy and the rate associated with the cost of that facility. Therefore, asserts the Ohio Commission, this Commission must not preclude a state from arriving at reasonable methods to ensure its generation clears the RPM capacity auctions.

4. Commission Determination

139. The mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules that could allow uneconomic entry has caused us to reexamine our acceptance of the existing state exemption, which we approved as part of the 2006 RPM Settlement Order.[75] For these reasons, we accept as just and reasonable PJM's proposal to eliminate the current state exemption.

140. However, we reject PJM's proposed replacement mechanism. PJM's proposed state exemption restates an affected party's right to file to prospectively change a filed rate schedule (other than its own), which is embodied in section 206 of the FPA. This is a statutory right, not a right created by contract.

141. The MOPR, as modified herein, sets forth reasonable procedures for establishing a bid floor for a new generating unit and, as discussed earlier, the tariff will provide a mechanism by which a generating unit may seek to establish a different rate for a competitive bid if it believes its costs are lower than

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[75] In the 2006 RPM Settlement Order, the Commission determined that current exemption "is reasonable because it enables states to meet their responsibilities to ensure local reliability." 2006 RPM Settlement Order, 117 FERC 61,331 at P 104. We note that removing this provision from PJM's tariff in no way impairs the ability of a state to request an exemption for reliability reasons under section 206.

those in the default bid.[76] Further, the MOPR does not interfere with states or localities that for policy reasons seek to provide assistance for new generation entry if they believe such expenditures are appropriate for their state. The MOPR ensures only that the wholesale capacity market prices remain at just and reasonable levels. The Commission has previously found, and we reiterate here, that uneconomic entry can produce unjust and unreasonable wholesale rates by artificially depressing capacity prices, and therefore the deterrence of uneconomic entry falls within our jurisdiction.[77] It is the potential for these unjust and unreasonable outcomes in a Commission-jurisdictional market that is the focus of our actions here.

142. Furthermore, as argued by the Pennsylvania Commission, among others, effective mitigation of uneconomic entry into wholesale capacity markets does not encroach on a state's ability to act within its borders to ensure resource adequacy or to favor

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[76] Furthermore, as required here, such a demonstration by a generating unit will not in the first instance involve a section 206 petition, and therefore concerns about timing, whether because an incumbent generator could forestall Commission action until after an auction, or because the Commission would have to determine the effect of a bid on clearing prices before an auction, are absent. Also, as pointed out by the Pennsylvania Commission, the IMM and EPSA, states seeking full independence in resource procurement choices can implement a form of capacity procurement that complements the RPM or can opt out of the RPM markets via the FRR alternative, an option discussed more fully in Section V.K. below.

[77] *PJM Interconnection*, L.L.C., 128 PERC 61,157, at P 90-91 (2009). See also NYISO, 124 PERC 61,301 (2008), *order on reh 'g*, 131 PERC 61,170 (2010), *rehearing pending*.

particular types of new generation.[78] In response to the Ohio Commission's request, we reiterate that states are free to promote all of those policies. However, as the Pennsylvania Commission notes, there is no valid state interest in ensuring that uneconomic offers can submit below-cost offers into the RPM auction.

143. We reject CPV Power's assertion that only if the IMM or other party can demonstrate that a project resulted from a state-mandated process intended solely to suppress wholesale capacity prices should it be mitigated. While the Commission acknowledges the rights of states to pursue legitimate policy interests, and while, as we have said, any state is free to seek an exemption from the MOPR under section 206, it is our duty under the FPA to assure just and reasonable rates in wholesale markets. As the Pennsylvania Commission notes, without effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets. Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's jurisdiction, and we are statutorily mandated to protect the RPM against the effects of such entry.

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[78] The Commission has found that, for example, "our action in approving in the NYISO's minimum bid proposal does not adversely affect [the New York Public Service Commission's] regulation of resource adequacy in [New York City because] ... [t]his new pricing methodology does not prescribe whether or what types of generation facilities should be built[.]" NYISO Mitigation Order, 122 FERC 61,211 at P 112.

H. Resources Subject to Mitigation

144. PJM's MOPR currently allows zero-price offers for nuclear, coal, integrated gasification combined cycle (IGCC) facilities and hydroelectric resources.

1. PJM's Proposal

145. PJM proposes to add wind and solar facilities to the MOPR provision that currently allows for zero-price offers, and PJM also proposes to eliminate its existing zero-price allowance for upgrades or additions to an existing capacity resource.[79] PJM states that the net cost of wind and solar resources, which are intermittent resources, will bear little relation to the Net Asset Class estimates that will be determined under PJM's OATT for CC and CT plants and may be complicated by credits and incentives. PJM asserts that an existing resource is a planned resource if it adds capacity and that adding capacity to an existing CC or CT plant may well be an effective means of pursuing a price-suppression strategy.

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I. Duration of Mitigation

158. Under PJM's existing MOPR, mitigation is applied for one auction, i.e., for the first delivery year in which the resource qualifies as a Planned

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[79] PJM also proposes several clarifying changes, including deleting from the current zero-price allowance for nuclear, coal and IGCC facilities the term "base load" and the phrase "that require a period of development greater than three years." PJM states that deletion of these terms is warranted given that they add little to the list of technology types intended to be included within this provision and because their continued inclusion would invite unnecessary debate regarding the scope and application of these terms.

Generation Capacity Resource, [82] regardless of whether the resource clears.[83]

1. PJM's Proposal

159. PJM proposes to apply its MOPR to a Planned Generation Capacity Resource in all base residual auctions up to and including the second successive base residual auction after the base residual auction in which the new entrant's resource clears. PJM asserts that this is consistent with findings made by the Commission regarding the abilities and incentives of a new entrant to suppress prices.[84] PJM also argues that its proposal is appropriate because it matches the three-year lag between the time a Planned Generation Capacity Resource first clears a base residual auction and the time it would enter commercial operation for the first delivery year for which it is committed. PJM states that, in the interim, there will be two additional base residual auctions in which the Planned Generation Capacity Resource would presumably offer, but not yet be in service and still have considerable avoidable project investment and development costs.[85]

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[82] A Planned Generation Capacity Resource is a resource that is participating in the interconnection process. Once a resource begins to receive interconnection iervice, it is no longer classified as a Planned Generation Capacity Resource. *See* PJM Reliability Assurance Agreement at Section 1.70.

[83] PJM OATT, Attachment DD at Section 5.14(h)(2).

[84] PJM Filing at 19-20, (citing NYISO Mitigation Order, 122 FERC 61,211 at P 114-16; ISO Capacity Market Revisions Order, 131 FERC 61,065 at P 83).

[85] PJM notes, for example, that a planned generation capacity resource that offers into the 2014-15 base residual auction in May 20 11 for first time and clears, expecting to be in-service three years later, i.e., just prior to the 2014-15 delivery year, is still considered to be "planned" in the following two actions, since it

PJM states that its proposal is required in order to cover the period during which the costs of the new resource are not fully sunk, thereby recognizing the resource's ongoing ability, during this period, to affect clearing prices.

2. P3's Proposal

160. P3 proposes to continue mitigation until a resource proves that it is economic by clearing in two base residual base auctions. Resources that clear in two capacity auctions would thereafter be permanently exempt from mitigation.[86] P3 argues that such an approach is the closest approximation to the Commission's recently-approved standard for the NYISO. [87]

161. P3 argues that this revision is necessary because the existing single year limitation can be easily circumvented by offering a resource into an auction at a high price prior to the time when it is anticipated to be ready. P3 notes that such an offer would then fail to clear and the resource would complete its one-year mitigation period close to its

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will likely not yet be in- service at the time of those two subsequent auctions.

[86] Under P3's proposal, a resource that previously cleared only in part would only be exempt from mitigation for that portion of its offer that cleared. For example, if a 500 MW resource was offered in the previous base residual auction, but only 200 MW cleared, the 200 MW would thereafter become exempt from the MOPR.

[87] NYISO Mitigation Enhancements Order, 133 FERC ¶ 61,178 at P 51 (finding that any resource that is not clearing in the market is uneconomic and requiring that mitigation continue, regardless of how long the resource has already been subject to mitigation).

start-up date. P3 adds that even without such machinations, a one-year mitigation period does virtually nothing to remove the ability and incentive to exercise buyer market power. P3 argues that the resources used to artificially depress capacity prices have a useful life of several decades and that an uncompetitive resource will depress capacity market clearing prices in every year it participates, not merely the first year.

162. P3 also argues that the MOPR is inappropriately limited to base residual auctions, and should also apply to incremental auctions. P3 notes that, while prices and volumes in the incremental auctions may be smaller than those in the base residual auctions, the exemption for incremental auctions still permits resources that are otherwise mitigated by the MOPR to begin to suppress prices even in the first year of operation.

3. Responsive Pleadings

163. A number of intervenors generally agree with PJM and P3 that subsidized resources could re-bid in subsequent years and suppress prices absent the extension of the MOPR. The length of duration supported by these intervenors, however, varies. Some argue that the duration should last until the resource is competitive.

164. Other intervenors argue that the PJM and P3 proposals are unworkable because: (i) both proposals would further impair the finance ability of projects developed pursuant to the RPM; and (ii) a new capacity resource would be required to construct the facility so as to meet its commitments in the first base residual auction that it clears, with no certainty as to whether it would clear (and receive capacity

payments) for additional base residual auctions. LS Power states that, once a resource clears the base residual auction, it has been deemed economic and should not be subject to future mitigation if the market conditions and assumptions underlying its bid change. CPV Power requests that the time period for the proposed MOPR be revised such that the MOPR would apply to new entry offers for every year until an entrant clears its first base residual auction or for three years following its in-service date, whichever is earlier.

165. LS Power states that, alternatively, another option to explore (during a paper hearing) would be to extend the New Entry Price Adjustment term and apply the MOPR conterminously with that extended term, providing revenue assurance for the generator and mitigation of the capacity sell offer for the term of the New Entry Price Adjustment.

166. The Pennsylvania Commission argues that PJM's proposal is a just and reasonable approach. Hess submits that the Commission should approve the three-year period on the condition that, rather than requiring a developer to obtain Commission approval to use unit-specific net CONE, PJM examines on a unit-specific basis a project's costs and revenue expectations to determine whether the new entry is economic.[88]

167. However, Dominion asserts that PJM's proposal to continue mitigation after a unit clears is not sufficiently supported; Dominion argues that such a rationale is at odds with the purpose of the MOPR, which is to prevent uneconomically low bids. CPV

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[88] Hess notes that, otherwise, extending mitigation from one year to three is not just and reasonable.

argues that PJM's proposal places a large risk on new generation resources, and because this risk cannot be factored into gross or net CONE, PJM's proposal would effectively bar new entry for any resource that requires capacity payments longer than one year to amortize construction costs and would further undermine the efficacy of the very process -the RPM- that is intended to facilitate such entry. LS Power argues that, once a project has been financed and begins construction, which would be shortly after clearing the first base residual auction, it no longer has "considerable avoidable project and investment and development costs," as PJM claims. The New Jersey Rate Counsel argues that while PJM's mitigation proposal might be an appropriate response to intentional efforts to suppress prices, it is not appropriate in a mitigation scheme focused on price impacts without regard to intent.

168. The New Jersey Rate Counsel also argues that the MOPR should apply for one year and proposes that the IMM, or any market participant, could file under FPA section 206 to have mitigation extended for any resource that they believe should be mitigated longer. The PJM Load Group asserts that P3 has offered no proof that the single-year mitigation limitation has ever been circumvented and, at any rate, the fact that a rule can be circumvented is no reason to find it unjust and unreasonable. The PJM Load Group concludes that P3's proposed remedy would deter the new entry of resources whose costs are low enough to trigger mitigation.

169. The PJM Load Group argues that P3's claim that its proposal is similar to mitigation in the NYISO is not sufficient evidence that a proposal to expand mitigation indefinitely is appropriate. The PJM Load

Group states that a major distinction between New York City and anywhere else is the issue of open and competitive new entry and that, while there is general agreement that entry in New York City is difficult, there is no indication of such limitations in PJM.

170. The IMM states that the competitive offer of a new resource participating in its second base residual auction, after clearing in its first base residual auction, is the avoidable cost rate, not net CONE. The IMM argues that, as such, the MOPR should not create barriers to entry by creating risks for new entrants. The IMM further argues that the P3 and PJM proposals would place an unnecessary burden on the potential entrant by requiring the resource's costs to match the relevant market signal for one, or two, additional years and that such a requirement would act as a deterrent to competitive entry The IMM further states that such an approach would put the new entrant at risk of being forced out of the market by predatorily-priced capacity additions to an incumbent's existing generation designed to defeat and deter new entry.

171. The IMM states that the MOPR should require that a unit clear one base residual auction based on an offer of net CONE, or its demonstrated individual net CONE, and demonstrate that it is not receiving any subsidies and has not contracted to receive any subsidies. From then on, any offer would be acceptable, subject to the ongoing requirement to demonstrate that it is subsidy-free and subject to the avoidable cost rate- based caps. The IMM further argues that offer floors should apply to new resources in all auctions, including both base residual auctions and incremental auctions.

4. Commission Determination

172. For the reasons discussed below, we agree that PJM's existing tariff needs to be revised. However, we find that PJM's proposed revision is unreasonable and we will accept it subject to revision.

173. PJM's existing tariff provides that the MOPR is applied only once- namely, to the offer made in the base residual auction for the first delivery year in which the resource qualifies as a capacity resource. Such a provision, however, still permits a resource to submit a less than competitive bid in the second auction that results in an unjust and unreasonable reduction in price. For this reason, we conclude that the existing MOPR provision that limits the application of an offer floor to one auction is not reasonable.

174. We also conclude that PJM's proposed revision is not just and reasonable, and therefore, we reject it. In some instances, PJM's proposal would unreasonably remove the offer floor before the resource has demonstrated that it is needed by the market. That is because PJM would apply the offer floor only to Planned Generation Capacity Resources, which are resources that are participating in the interconnection process. [89] Once a resource begins to receive interconnection service, it is no longer classified as a Planned Generation Capacity Resource, and thus, it would not be subject to the offer price floor under PJM's proposal. A resource could lose its status as a Planned Generation Capacity Resource before the resource has cleared a capacity auction, thereby enabling an uneconomic resource to bypass the MOPR and successfully and artificially suppress capacity prices.

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[89] *See* PJM Reliability Assurance Agreement at Section 1.70.

175. On the other hand, PJM's proposal also mitigates resources that should not be mitigated. PJM's proposal would apply the offer floor to a resource that has already cleared in a PJM capacity auction, and thus, that has already demonstrated that it is needed by the market. In these instances, PJM's proposal would unreasonably apply the offer floor to an economic resource and could therefore inefficiently discourage the entry of new capacity that is economic. That is because PJM proposes to apply the offer price floor to a Planned Generation Capacity Resource for two base residual auctions beyond the first auction in which the resource clears. We agree with the IMM that once a new resource has cleared in one auction at the offer price floor, the resource has demonstrated that it is needed by the market and it is therefore economic. The resource's presence in the market at this point does not artificially suppress market prices, and there is no reasonable basis for continuing to apply the MOPR to it.

176. We agree with the IMM that the appropriate duration is that the MOPR offer floor should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost- by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry. Under such an approach, the MOPR would apply to any resource until it has proven that it is needed by the market and from that point forward, the resource would be treated as an existing capacity resource not subject to the MOPR. Unlike PJM's approach, the IMM's approach would not unfairly mitigate a resource (or require it to cost justify a lower bid) in the years after it has cleared the auction.

177. The IMM also suggests we add as a second requirement that the resource show it is not receiving discriminatory subsidies. We decline to add this requirement because even if discriminatory subsidies are being received, if the resource is needed at the MOPR bid then it is a competitive resource and should be permitted to participate in the auction regardless of whether it also receives a subsidy.

178. We therefore require PJM to submit tariff language in its compliance filing adopting the approach discussed above.

J. Sunset Provisions

1. PJM's Proposal

179. PJM proposes to delete the sunset provision, pursuant to which the MOPR automatically terminates when there is a positive "Net Demand for New Resources" over a period of consecutive years beginning with the first RPM delivery year in a specified portion of the PJM region that was not capacity-constrained at the time RPM was implemented. PJM states that the defined term, "Net Demand for New Resources," was deleted from PJM's OATT in 2009. PJM further asserts that the objectives served by the MOPR are not time-limited. As such, PJM states that the MOPR should not be subject to a sunset provision.

2. P3's Proposal

180. P3 proposes, like PJM, to delete the sunset provision.

3. Responsive Pleadings

181. EPGA, Dayton, and the IMM support PJM's proposed elimination of sunsetting. The IMM argues that the objectives of the MOPR are not time-limited and that the only effect of the existing provision would

be to prevent application of the MOPR under possible future circumstances when the rule should apply.

4. Commission Determination

182. We accept PJM's proposal to delete the sunset provision. We agree with PJM that the objectives of the MOPR are not time-limited. Furthermore, the provision is no longer necessary because it relies upon a definition of "net demand for new resources" from an RPM tariff rule that has been deleted.

137 FERC ¶ 61,145 (Exh. D235)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20126

(Issued November 17, 2011)

Docket No. ER11-2875-001
Docket No. ER11-2875-002,
EL11-20-001 (Unconsolidated)

PJM INTERCONNECTION, L.L.C.
PJM POWER PROVIDERS GROUP

v.

PJM INTERCONNECTION, L.L.C.

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller,
John R. Norris, and
Cheryl A. LaFleur.

ORDER ON COMPLIANCE FILING, REHEARING, AND TECHNICAL CONFERENCE

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I. INTRODUCTION

1. We address below requests for rehearing and clarification of an April 12, 2011 order issued in this proceeding, including those requests for which additional procedures, including a technical conference proceeding, were established.[1] We also address a compliance filing submitted by PJM Interconnection, L.L.C. (PJM) on May 12, 2011. For the reasons discussed below, we grant, in part, and deny, in part, rehearing of the April 12 Order. We also accept, in part, and reject, in part, PJM's compliance filing and direct PJM to submit an additional compliance filing within 30 days of the date of this order.

2. At issue in this order is PJM's Minimum Offer Price Rule (MOPR), which is the mechanism that seeks to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Pricing Model (RPM) on a competitive basis. The MOPR imposes a minimum offer screen to determine whether an offer from a new resource is competitive. We continue to conclude that the MOPR serves a critical function to ensure that wholesale prices are just and reasonable and should elicit new entry when new capacity is needed. The long-term viability of the PJM market demands an assurance of competitive offers from new entrants.

3. Some parties in this proceeding have argued that RPM has failed to attract sufficient capacity, requiring state and local entities to take action to encourage the development of new capacity resources in their areas. These parties argue that the MOPR will impede states'

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[1] PJM Interconnection, L.L.C., 135 FERC ¶ 61,022 (2011) (April 12 Order).

and localities' efforts to build new resources to ensure reliability by mitigating certain projects. We note at the outset that the evidence before us suggests that RPM has in fact succeeded in securing sufficient capacity to meet reliability requirements for the PJM region.[2] We also recognize that states and localities have their own policies and objectives that they wish to carry out, and the benefits of some of these policies and objectives may not be recognized in the RPM construct generally or the MOPR in particular. Our intent is not to pass judgment on state and local policies and objectives with regard to the development of new capacity resources, or unreasonably interfere with those objectives. We are forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's RPM is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity.

4. We believe that the MOPR that we accept subject to modification in this proceeding, including the unit-specific review process proposed in PJM's compliance filing, serves to reconcile the tension that has arisen between policies enacted by states and localities that seek to construct specific resources, and our statutory obligation to ensure the justness and the reasonableness of the prices determined in the RPM. First, we note that PJM only proposed, under section 205, and we accepted based on the record before us, to apply the MOPR to new gas-fired facilities.

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[2] *See* Second Performance Assessment and CONE Study, prepared for PJM Interconnection, L.L.C. by The Brattle Group (August 18, 2011); Brattle Report Second Performance Assessment of PJM Reliability Pricing Model (August 26, 2011).

5. Second, while we continue to find that an across-the-board exemption from MOPR for new resources designated as self-supply would allow for an unacceptable opportunity to exercise buyer market power and inhibit competitive investment, we agree with PJM and those intervenors who argue that well-recognized business models should not be considered automatically suspect when determining whether a sell offer accurately reflects avoidable net costs. We therefore find that a unit-specific cost justification process, as proposed by PJM, will allow PJM to consider project costs as well as revenues the project would receive on a competitive basis and will mitigate much of the concern parties have about the possibility of having their capacity market offers mitigated solely on the basis of triggering the MOPR.

6. Third, in addition to the unit-specific review process, we emphasize that states and localities also retain the statutory right under section 206 of the Federal Power Act (FPA) to seek an exemption from the MOPR if they believe that the MOPR unjustly and unreasonably interferes with a legitimate policy objective.

II. BACKGROUND

7. On February 1, 2011, the PJM Power Providers Group (P3)[3] filed a complaint, seeking expedited

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[3] P3 is a non-profit organization made up of twelve member companies, namely Calpine Corporation; Constellation Energy Group; DPL Energy; Edison Mission Energy; Exelon; GenOn Energy Management, LLC (GenOn); International Power America; NextEra Energy Resources, LLC; North American Energy Alliance LLC; NRG Energy; PPL Parties; and PSEG Energy Resources & Trade LLC (PSEG). P3 states that the content of its complaint represents the position of P3 as an

revisions to PJM's capacity procurement minimum offer price mechanism, the MOPR,[4] in response to certain state-sponsored initiatives designed to

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the long-term cost and revenue considerations that may influence the determination to bring a new resource on line, including revenues from outside of PJM's markets.[32] The other concerns related to the unit-specific review process will be discussed in the section addressing PJM's Compliance Filing, below.

F. STATE MANDATED EXEMPTION

77. PJM proposed to eliminate its MOPR exception for state policy projects, which allowed for an exemption for a new entry sell offer based on a resource "that is being developed in response to a state regulatory or legislative mandate to resolve a projected shortfall," so long as that determination was made in a state evidentiary proceeding "that includes due notice, PJM participation and an opportunity to be heard." PJM

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organization, but not necessarily the views of any particular member with respect to any issue.

[4] *See* PJM Open Access Transmission Tariff (OATT) at Attachment DD, Section 5.14(h).

[32] As discussed below, PJM's compliance filing generally concurs with this position, proposing that a sell offer, upon review, be found justified based on competitive cost advantages relative to the costs estimated for the MOPR screen, including costs resulting from the capacity market seller's business model, financial condition, tax status, access to capital, other similar conditions affecting the applicant's costs, and/or net revenues.

proposed instead to make MOPR exemptions requested on state policy grounds subject to receipt of a section 206 ruling. [33]

1. April 12 Order

78. The April 12 Order accepted PJM's proposal to eliminate its state mandate exemption, but it rejected PJM's proposed replacement mechanism as duplicative of the existing statutory rights established under FPA section 206 of an aggrieved entity to petition the Commission for a tariff change or waiver.[34]

2. Requests for Rehearing

79. The Maryland Commission and the New Jersey Board argue that the Commission erred in approving the elimination of the state mandate exemption. These parties argue that their states face serious reliability needs, persistent congestion, and looming reliability violations that the RPM has failed to meet. The Maryland Commission adds that the April 12 Order disregarded testimony from the Maryland Commission Chairman Nazarian addressing the gravity of the reliability concerns in Maryland and approved the elimination of the state mandate exemption without due consideration of states' legitimate interests in assuring that sufficient resources are available to serve customers reliably.

80. The New Jersey Board asserts that the Commission's rulings exceeded the Commission's FPA section 205 and section 206 authority. The New Jersey Board argues that eliminating this, exemption required the Commission to make a finding that this provision was

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[33] P3, in its complaint, proposed to eliminate the exemption altogether.

[34] April 12 Order, 135 FERC ¶ 61,022 at P 139.

no longer just and reasonable. The New Jersey Board adds that even if such a finding was implicit in the April 12 Order, the Commission's findings were otherwise unsupported, and will substantially impede the implementation of New Jersey's capacity procurement program. The New Jersey Board requests that the Commission direct PJM to reinstate the preexisting exemption for state sponsored projects or, alternatively, exempt from mitigation the capacity resources approved by the New Jersey Board pursuant to the state's Long-Term Capacity Agreement Pilot Program (LCAPP).

81. New Jersey Rate Counsel argues that the Commission's elimination of the state mandate exemption converts a mechanism designed to address real-world capacity deficiencies into an untenable choice requiring the state to either file a complaint at the Commission or opt out of RPM entirely.

82. A number of parties argue that the April 12 Order erred in not enumerating the specific evidence upon which it relies, merely citing the "mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules."[35] New Jersey Rate Counsel and Dominion further assert that the Commission failed to support its departure from the 2006 RPM settlement agreement,[36] of which the state mandate exemption was an important component.

83. The Maryland Commission argues that the Commission's ruling was erroneously based on the

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[35] *Id.*

[36] PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

assumption that state action constitutes an impermissible exercise of buyer market power. The Maryland Commission adds that because alleged exercises of buyer market power by states do not benefit the states directly, the legitimate policy goals that state agencies are charged with fulfilling should be considered with respect to the issue of intent.

84. Petitioners also argue that the Commission's ruling was internally inconsistent. Specifically, Dominion asserts that while rejecting the state policy exemption based on economic theory and the risk to the market of allowing units with retail price support to participate, the Commission nonetheless accepted exemptions applicable to wind, solar, coal, nuclear, and hydro-electric generation, as well as integrated gasification CC generation, regardless of whether these resources do, or do not, have regulated rate support and regardless of their price impact on the market. The Maryland Commission argues that the Commission failed to explain why anticipated effects on prices, irrespective of intent, are the determinative factor when evaluating whether to mitigate offers from new resources in some instances, while in others, a developer's imputed lack of improper purpose justifies an exception. Dominion adds that the Commission's rationale for exempting these categories of resources applies equally to gas-fired facilities selected through state-sanctioned integrated resource planning.

85. Dominion argues that, if a waiver request must be made with the Commission, it should not be made pursuant to section 206, but simply as a petition or a motion. Dominion adds that an aggrieved party should not be required to demonstrate, under section 206, that PJM's existing tariff is unjust and unreasonable

or that its proposed alternative is just and reasonable. The New Jersey Board argues that requiring a state entity to seek section 206 relief in order to carry out its own policies of promoting new capacity development will be unduly burdensome and will subject these entities to unwarranted delays. Regardless, the New Jersey Board argues that because a Commission determination would be made prior to the relevant RPM auction, it would be impossible for the Commission to determine whether the offer at issue will affect market- clearing prices.

86. Finally, petitioners challenge the Commission's finding that states seeking full independence in resource procurement choices can implement a form of capacity procurement that complements RPM or can opt out of the RPM market via the Fixed Resource Requirement (FRR) alternative.[37] The New Jersey Board argues that the Commission's finding was unaccompanied by any analysis or discussion explaining how, or whether, the Commission's finding could be implemented. The Maryland Commission adds that the FRR option was never intended to be a mechanism that would permit states to initiate procurement of new resources to address state policy

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[37] April 12 Order, 135 FERC ¶ 61,022 at P 141, n.76. An entity that chooses the FRR alternative submits an FRR capacity plan to PJM, a long-term plan for the commitment of capacity resources to satisfy the entity's capacity obligations. The area covered by the plan is: (i) the service territory of an investor owned utility; (ii) the service area of a public power entity or electric cooperative; or (iii) a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, and for which the FRR entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. *See* PJM Reliability Assurance Agreement at Schedule 8.1.

goals and is otherwise incompatible with that purpose, given its restrictive rules.[38]

3. Commission Determination

87. We deny rehearing of the April 12 Order with respect to the Commission's acceptance of PJM's proposal to eliminate the state mandate exemption. We also deny rehearing with respect to the Commission's rejection of PJM's proposed replacement mechanism. PJM's filing under section 205 proposed to eliminate a provision in section 5.14(h)(l)(iv) that excluded from the MOPR: "any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard."[39] PJM also proposed to include in section 5.14(h)(5) the following provision that permitted a resource to demonstrate, under section 206, that: "the Sell Offer is based on new entry that is pursuant to a state-mandated requirement that furthers a specific legitimate state objective and that the Sell Offer would not lead to artificially depressed capacity prices or directly and adversely impact FERC's ability to set just and reasonable rates for capacity sales in the PJM Region or any affected Locational Deliverability Area."[40]

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[38] *See* New Jersey Rate Counsel Rehearing Request at 79.

[39] OATT at Attachment DD, Section 5.14 Clearing Prices and Charges, 2.0.0(h)(l)(iv).

[40] *Id.* at 4.0.0, §(h)(5)(B).

88. The Commission accepted PJM's proposal to eliminate the provision as worded in section 5.14(h)(l), but rejected PJM's revised proposal for the state exemption. The Commission reasoned that the revised "state exemption restates an affected party's right to file to prospectively change a filed rate schedule (other than its own), which is embodied in section 206 of the FPA. This is a statutory right, not a right created by contract."[41] Thus, the Commission's order did not eliminate a resource's or a state's right to petition the Commission under section 206 to permit an exemption from the MOPR rules. The order found only that such a right is statutory, and need not be included in the tariff.

89. The Maryland Commission and the New Jersey Board assert that the Commission disregarded their states' purported unmet reliability needs and did not properly consider their legitimate interests in assuring that the reliability needs of their citizens are met. RPM is structured to allow PJM to acquire sufficient capacity resources to meet the reliability needs of the entire PJM region, including all the states in that region, on a three-year forward basis. Nevertheless, the April 12 Order found, and we reaffirm here, that the MOPR does not interfere with states or localities that, for policy reasons, seek to provide assistance for new capacity entry if they believe such expenditures are appropriate for their state. We only seek to ensure the reasonableness of the wholesale, inter-state prices determined in the markets PJM administers.

90. RPM itself, however, has no feature to explicitly recognize, for example, environmental or technological

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[41] April 12 Order, 135 FERC ¶ 61,022 at P 140.

goals, nor does it contemplate reliability concerns beyond a three-year forecast. If PJM market participants agree that RPM should account for resource attributes that reflect broader objectives than three-year forward reliability, then PJM and its stakeholders should begin a process to consider how to incorporate these features into RPM's market design. In this way, all capacity resource suppliers will be able to receive a non-discriminatory market clearing price that reflects these values in addition to reliability. But allowing selected new projects to bid into RPM as price-takers because they are state-mandated would undermine the objective of RPM to procure the least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives on a three-year forward basis.

91. The MOPR helps to ensure that the wholesale capacity market prices remain at just and reasonable levels. Removal of this provision does not eliminate the ability of states to bring their concerns to the attention of the Commission. States can file under section 206, or participate in filings by generators, if they believe that the MOPR interferes with a legitimate state objective. We therefore reject the New Jersey Board's request to reinstate the state policy exemption or, in the alternative, grandfather the capacity resources approved pursuant to the state's LCAPP.

92. Several parties argue that the Commission's state mandate exemption findings were procedurally deficient. The New Jersey Board argues that the Commission erred in arbitrarily choosing to eliminate the state mandate exemption pursuant to PJM's section 205 filing rather than pursuant to P3's section

206 proposal to eliminate the same provision.[42] The New Jersey Rate Counsel argues that the Commission did not have the option of eliminating the state mandate exemption under section 205. This is because, according to the New Jersey Rate Counsel, PJM proposed to retain an exception for offers that are justified on state policy grounds, but to place it under the same process as any other sell offer seeking a MOPR exception. According to the New Jersey Rate Counsel, given the Commission's rejection of PJM's proposed replacement mechanism, the Commission could only have eliminated the state mandate exemption by making a finding under section 206 that the existing provision was unjust, unreasonable, unduly discriminatory or preferential. The New Jersey Rate Counsel asserts that the Commission made no such finding. The New Jersey Board argues that the Commission has not supported its state policy exemption decision even under section 205 because the Commission did not provide a well reasoned explanation of its finding that the preexisting reliability-based exemption was unjust and unreasonable nor any evidence of problems created by the MOPR exemption.

93. We disagree. PJM voluntarily filed to eliminate its then-effective state exemption in section 5.14(h)(1)(iv) under section 205, and we accepted that portion of PJM's filing. Under the previously-existing provision, PJM would have to determine whether the state proceeding was based on "projected capacity shortfall in the Delivery Year affecting that state" and also required that PJM be accorded certain procedural rights. We agree with PJM that the previously-

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[42] New Jersey Board Rehearing Request at 23.

effective state exemption provision improperly required PJM to assess the adequacy of state administrative processes and determine whether an offer was legitimately intended to address a projected capacity shortfall-a task that PJM is not well-suited to perform, as PJM itself acknowledged. Thus, we found that this element of the PJM proposal was just and reasonable.

94. Under section 205, PJM proposed to include a provision that would have established certain parameters applicable to a section 206 filing with the Commission relating to a state mandate. The Commission found PJM's proposal unjust and unreasonable because it established tariff prerequisites for a section 206 filing. As noted above, states and generating resources retain their statutory right to file complaints under section 206 unencumbered by the parameters proposed by PJM.

95. We therefore find that these were two separate proposals by PJM under section 205 for two different reasons.[43] We did not seek to modify or change either of PJM's proposals under section 206; we accepted one and rejected the other and did not mandate a change in PJM's tariff. Hence, we acted pursuant to section 205 with respect to each prov1s10n.

96. Moreover, even if our action were construed as a modification to PJM's proposal, we find that our actions in the April 12 Order satisfied the requirements of section 206. First, as indicated above, PJM's tariff prior to the April 12 Order was unjust and unreasonable because the state exemption created a

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[43] PJM did not contend that its proposal to remove the existing state exemption was conditioned on acceptance of its proposed revised state exemption and it did not seek rehearing on this issue.

loophole permitting uneconomic entry affecting the wholesale price. As the Pennsylvania Commission pointed out, and as we found in the April 12 Order, the state exemption in PJM's tariff prior to the April 12 Order may have adversely affected other states that wanted to rely on prices in the capacity market to incent new entry as opposed to relying on state funding.[44] In addition, and as discussed above, we agree with PJM that the previously-effective tariff provision was unjust and unreasonable because it would put PJM in the position of judging the quality and bases of state proceedings. We also continue to find that having no specific state exemption in PJM' s tariff is just and reasonable. As a general matter, we affirm our finding that permitting a state exemption generally would be inconsistent with the rationale and basis for the MOPR:

> [W]ithout effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets. Because below-cost entry suppresses capacity prices and because the Commission has exclusive jurisdiction over wholesale rates, the deterrence of uneconomic entry falls within the Commission's juris-diction, and we are statutorily mandated to protect the RPM against the effects of such entry.[45]

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[44] *See* April 12 Order, 135 FERC ¶ 61,022 at P 143 ("[W]ithout effective mitigation of state-sponsored uneconomic entry, the actions of a single state could have the effect of preventing other states from participating in wholesale markets.").

[45] *Id.* P 143.

97. We continue to agree with the IMM that permitting a state exemption may in fact, over the long run, result in less investment in capacity and demand-side resources and the need in the future for additional subsidies from the state.[46] Such a result would also, as we note elsewhere, impact capacity clearing prices more broadly, with the potential to impact other states that have chosen to rely on the price signals provided by the wholesale market. Our statutory responsibility here is to ensure that the markets (the rules, etc.) are just and reasonable to ensure that just and reasonable rates are produced. If a state believes that operation of the MOPR in a particular situation is unjust and unreasonable, it can file with the Commission under section 206 or 306 of the FPA.

98. The Maryland Commission argues that buyer market power and seller market power should not be treated equivalently in fashioning mitigation. Even if so, however, Commission and court precedent indicate that PJM needs to protect against both buyer market power and seller market power to ensure competitive, properly functioning markets.[47] The Maryland Commission has not justified any relevant disparate treatment on this record.

99. The New Jersey Rate Counsel, the New Jersey Board and Dominion argue that the Commission erred in requiring a party seeking an exemption on state policy grounds to file a section 206 complaint; the

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[46] IMM's March 4, 2011 Comments at 2, 8-9

[47] *See Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) (characterizing a competitive market as one in which neither the buyer nor seller has significant market power); Energy Transfer Partners, L.P., 120 FERC ¶ 61,086, at P 31 (2007) ("The direction in which the manipulative conduct moves the price is immaterial to its legality.").

latter two parties claim that such a procedure is unduly burdensome and will engender delay. In response to concerns about timing, we note that nothing prevents a state party from filing prior to initiating the administrative process necessary to solicit new resources. We further clarify that the April 12 Order did not limit the right of a state, or a state agency, under the FPA. Nothing precludes a state party from filing a petition for declaratory order with the Commission, but the ultimate vehicle that will be required to establish that mitigation rules are unjust and unreasonable as applied to a particular project is a section 206 complaint.

100. Some parties argue that the FRR alternative may not be a viable substitute for many RPM participants. But this is an individual determination to be made by each state and distribution company. PJM's tariff provides this alternative method of satisfying resource requirements while preserving wholesale market prices, and states and distribution companies can make this choice based on their individual circumstances.

101. Finally, we reject the rehearing arguments of New Jersey Rate Counsel and Dominion regarding the Commission's acceptance of a proposal (the elimination of the state mandate exemption) that departs from the 2006 RPM Settlement. The Commission has modified provisions of the 2006 RPM Settlement in the past, both when proposed by PJM and on the Commission's own motion, where circumstances and the record presented warranted those changes.[48]

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[48] *See, e.g.*, PJM Interconnection, L.L.C., 126 FERC ¶ 61,275, at P 36 (2009) (accepting, among other things, new CONE values to be used in PJM's MOPR); Pepco Energy Services, *Inc. v. PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,051 (2009) (finding PJM's

Here, PJM itself argued that the state mandate exemption required revision because it could negatively affect the wholesale price in the capacity market.

H. DURATION OF MITIGATION

113. PJM proposed to apply its MOPR to a planned capacity resource in all base residual auctions up to and including the second successive base residual auction after the base residual auction in which the new entrant's resource clears.

1. April 12 Order

114. As discussed below, the April 12 Order rejected PJM's proposed duration of mitigation provision. The April 12 Order noted that under PJM's then-existing tariff, the MOPR was applied only once to the offer made in the base residual auction for the first delivery year in which the resource qualifies as a capacity resource. The Commission found, however, that this allowance permitted a resource to submit a less than competitive bid in the second auction that could result in an unjust and unreasonable reduction in price. The Commission found on this basis that PJM's then-existing provision was unjust and unreasonable and must be revised.

115. As a replacement mechanism, the Commission found that a MOPR offer floor would be required for each new resource in the base residual and each incremental auction until such time as the resource demonstrates that its capacity is needed by the market at a price near its full entry cost by clearing in one of

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RPM rules governing the peak-hour period availability charge for infrequently run generators to be unjust and unreasonable).

the PJM capacity auctions (base residual or incremental) at an offer price near its full cost of entry.

2. Requests for Rehearing

116. Hess asserts as error the April 12 Order's requirement that the MOPR offer floor apply to new resources in the RPM base residual and incremental auctions until such time as the resource submits an offer price that clears. Hess argues that the MOPR could be applied to a new resource in perpetuity and is unsupported and otherwise unjust, unreasonable and anticompetitive. Hess adds that such a requirement will deter entry of new resources, including economic new entry. In particular, Hess argues that the Commission failed to consider the impact of its ruling on developers that have invested time over the years in their projects based on reliance on the previously-effective MOPR requirement. Hess asserts that market participants that have relied in good faith on PJM's prior rule should be exempted from PJM's new requirement.

117. Hess also argues that the Commission exceeded its statutory authority under FPA section 205 and failed to satisfy the requirements of FPA section 206 when it rejected PJM's proposal but then issued its own mandate (based on a proposal made by the IMM, an entity that lacks section 205 filing rights).

118. NCEMC notes that while the April 12 Order, found that "the MOPR offer floor should apply to each new resource [until the resource has] clear[ed] one of the PJM capacity auction[s]," the Commission failed to define its use of the term "new resource." NCEMC therefore requests that this term be clarified, on rehearing, by finding that the MOPR does not apply to existing capacity resources, as defined in the PJM

tariff, regardless of whether these resources have, or have not, cleared in (or previously bid into) an RPM auction. NCEMC argues that, absent this clarification, PJM's tariff could be interpreted in a way that could have an adverse effect on load serving entities (LSE) seeking to self-supply their RPM capacity obligations by use of existing resources. NCEMC also points out that an LSE may, for example, seek to use an existing resource from an external control area and that such a resource may have never before offered into PJM auction, thus subjecting it to the MOPR.

119. First Energy, P3 and PPL argue that the Commission's requirement that a resource remain subject to the MOPR until it has cleared in one capacity auction, without more, will be insufficient to ensure that the resource is economic.[54]

120. PPL argues that for an entity seeking to artificially depress capacity prices over the long run, the occurrence of price swings coupled with the MOPR duration requirement adopted in the April 12 Order will create a substantial opportunity for evading mitigation.[55]

121. P3 asserts as error the April 12 Order's rejection of P3's proposal to subject a resource to mitigation for three years after it first clears and requiring the resource to either clear twice or a demonstrate that it is not receiving any subsidies, which it calls the "No Subsidy" off-ramp.

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[54] PSEG Rehearing Request at 10.

[55] *See id.* at 13-15 (arguing that this appears to be the precise strategy employed by the State of New Jersey under LCAPP).

3. Commission Determination

122. For the reasons discussed below, we deny rehearing of the April 12 Order addressing the Commission's conditional acceptance of PJM's proposed duration of mitigation. We also grant, in part, and deny, in part, petitioners' clarification requests.

123. We reject Hess' argument that the MOPR duration period approved in the April 12 Order will discourage efficient new entry. Hess' concern about discouraging offers of new entry appears to be based on the assumption that the developer would need to incur significant costs to make its offer-costs that would not be recovered if the offer does not clear. But new resources will not be required to incur the majority of their costs before they clear in an RPM auction and can begin receiving capacity revenues. Gas resources (the only resources subject to the MOPR) typically can be constructed within three years. Thus, the construction of any such resource need not begin until it has cleared in the base residual auction, which is held three years in advance of the delivery year.

124. Hess is also concerned about the impact of the duration period on a resource that began construction prior to the effective date of PJM's February 11, 2011 Filing, in reliance on PJM's previous MOPR requirements, but did not clear a base residual auction in the first delivery year. Hess argues that subjecting such a resource to the new MOPR requirements is unfair. However, if the resource is not needed by the market (based on the going-forward costs that would be incurred under PJM's new requirements), its entry would inefficiently suppress capacity market prices. Under these circumstances, we conclude that subjecting such a resource to the MOPR is reasonable. We

further note, however, that such a resource could seek a unit-specific, cost-justified reduction in its offer floor under the MOPR requirements, as the April 12 Order provides and as described in more detail in PJM's May 12, 2011 Compliance Filing proposal (discussed below).

125. Hess maintains that the Commission exceeded its statutory authority under FPA section 205 in requiring PJM to revise its provision. In this case, the Commission acted pursuant to the section 206 complaint.[56] PJM voluntarily filed to eliminate its existing tariff because it contained a loophole: it applied only once, for the first delivery year in which the resource could be offered, so that a resource by sitting out one auction, could depress prices in a second auction without mitigation. The Commission agreed with PJM that its existing tariff was unjust and unreasonable. However, the Commission found that PJM's proposed replacement also was deficient and rejected it,[57] because it too would unreasonably remove the offer floor before the resource has demonstrated that it is needed by the market and also would mitigate resources for which mitigation was not required. The Commission agreed with the IMM that the appropriate duration is to apply the MOPR offer floor to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost-by clearing one of the PJM capacity auctions (base residual or incremental) at an offer price near its full

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[56] P3 also raised this issue in its February 1, 2011 section 206 complaint, arguing that mitigation should continue at least until the entrant clears in two auctions.

[57] April 12 Order, 135 FERC ¶ 61,022 at P 174.

cost of entry. The Commission required PJM to adopt this approach.[58]

126. Hess argues that the MOPR could be applied to a new resource in perpetuity. However, the MOPR requirements are in place to ensure that a resource does not submit a less than competitive bid that results in an unjust and unreasonable reduction in price. PJM's preexisting tariff applied the MOPR only once-namely, to the offer made in the base residual auction for the first delivery year in which the resource qualified as a capacity resource. PJM's prior rule permitted a resource to submit an uncompetitive bid in the second and subsequent auctions, the result of which could lead to an unjust and unreasonable reduction in price. As such, the April 12 Order found, and we reaffirm here, that the MOPR should apply until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost, by clearing one RPM auction at an offer price near its full cost of entry.

127. Under this requirement, we acknowledge that a new resource, at least in theory, could be subject to the MOPR for a number of years. But this result could occur only if the market had a sufficient supply of low-cost capacity such that the new resource would not be needed over this period of years.

128. We deny, in part, NCEMC's request for clarification regarding the application of the MOPR to existing resources. NCEMC argues the MOPR should not apply to any existing resource[59] as defined in

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[58] *Id.* P 178.

[59] An Existing Generation Capacity Resource shall be deemed to be in service ¶ interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and

the PJM tariff regardless of whether it clears in an RPM auction. We find that the MOPR properly applies to existing resources that have failed to clear a capacity auction. Under PJM's tariff, a resource becomes an "Existing Generation Capacity Resource" under the Reliability Assurance Agreement (RAA) once it commences interconnection service. But for any resource, interconnection service could commence without the resource clearing in an RPM auction. Under NCMEC's position, an uneconomic new resource could be built and begin receiving interconnection service, thereby becoming an Existing Generation Capacity Resource. It would then permanently escape the MOPR offer floor, and could subsequently offer at an artificially low offer price into RPM auctions, thereby suppressing the capacity price. Such an outcome would not be just and reasonable. As the Commission stated in the April 12 Order, the MOPR offer floor should apply to any resource until it has proven that it is needed by the market.[60]

129. We will grant, however, NCMEC's request for clarification with respect to imports. NCMEC notes that an LSE may seek to use an existing resource from an external control area and that such a resource may have never before offered into a PJM auction. As we noted in a case involving ISO-NE, when capacity and energy are imported from an external balancing area, determining the identity of the resource (or portfolio of resources) that is supporting the import is often

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electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). *See* RAA at Section 1.20B.

[60] April 12 Order, 135 FERC ¶ 61,022 at P 176.

difficult.[61] In addressing those circumstances, the Commission concluded that it is reasonable to treat capacity imports as existing capacity, and thereby not subject them to the MOPR offer floor, except where a specific new external resource is identified as the sole support for the import and where a significant investment, such as a new transmission line, is made to provide capacity to the importing RTO.[62] Here, for the same reason, we conclude that treating capacity imports into PJM similarly would be reasonable. Accordingly, we direct PJM to submit a compliance filing, within 30 days of the date of this order, to revise its tariff with respect to this issue.

130. We reject P3's and PPL's argument that clearing in one capacity auction is insufficient to prove that resources are economic. P3 and PPL assert that prices in a constrained capacity zone could temporarily rise above the offer floor for a single year based on temporary market conditions that would not continue over a sustained period. P3 and PPL claim that, as a result, clearing for a single year when prices are only temporarily above the offer floor would not indicate that a new resource was actually needed by the market over the long term. We are not persuaded by this argument. While predicting future market conditions is necessarily uncertain, and it is possible that capacity prices in a given zone may rise above Net CONE for only a year and then remain below that level for many subsequent years, such a price scenario is only one of many possibilities. Other outcomes are also possible, where prices rise above Net CONE in one or more years, then fall below Net CONE for one or

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[61] ISO New England, Inc., 135 FERC ¶ 61,029 at P 191 (2011).

[62] *Id.*

more years to reflect an increase in supply due to new entry, and then rise above Net CONE as demand growth "catches up" with the added supply. Moreover, a load serving entity may legitimately believe that the higher prices will continue and its investment would be a legitimate response to the prices it perceives.

131. Were we to adopt P3's suggestion, a new resource that was needed by the market over the long term might clear in one auction, but then fail to clear for one or more years (when prices are slightly below the offer floor) before prices resume levels above Net CONE thereby allowing the resource to clear again. In this latter scenario, the new resource would fail to receive capacity revenues during the second and perhaps other subsequent years, even though the resource cleared in its first auction and even though the average capacity price over time approximated Net CONE. Such an outcome could discourage economic entry. We conclude that clearing in one auction, whether the base residual auction or in an incremental auction, and committing to provide capacity for a full year, reasonably demonstrates that a new resource is needed by the market at a price near its full cost of entry and that it is reasonable not to subsequently apply the MOPR to such a resource.

132. We deny FirstEnergy's request to extend the MOPR beyond the first year that a resource clears for resources that receive any kind of out-of-market subsidy payments. As discussed above, a competitive offer would reflect the incremental, going-forward cost that the supplier would incur if its offer is accepted and its resource takes on a capacity obligation. For a potential new resource that has not yet been built, going- forward costs reflect the full cost of construction. Hence, a reasonable offer floor for a new resource

would be near the full Net CONE. But once a new resource has cleared an auction and its construction is completed, construction costs become sunk. At that point, the incremental costs of taking on a capacity obligation become much smaller, often approximating zero (possibly until near the end of the resource's useful life, when substantial maintenance and refurbishment costs may be necessary). Thus, once a resource clears an RPM auction at a price above its offer floor, a competitive offer would typically be very low, and often close to zero–regardless of whether the resource receives any out-of-market payments. Therefore, we find that not imposing an offer floor on any resource that has cleared an RPM auction at a competitive price is reasonable, even if the resource receives out-of-market payments.

133. Finally, we reject P3's argument that the MOPR should be revised to require resources to demonstrate that the unit is not receiving any subsidies or has not contracted to receive any subsidies. It defines the term "subsidy" to include any revenues from outside the organized PJM markets. Regardless of whether discriminatory subsidies are being received, a resource that has cleared an RPM auction at a price above its offer floor is needed and considered a competitive resource and should be permitted to participate in the auction without an offer floor regardless of whether it also receives a subsidy.

I. ADDITIONAL REHEARING ISSUES

1. Whether the MOPR Should Apply to Unconstrained Regions

134. 3 seeks clarification regarding the application of the MOPR to both constrained and unconstrained

regions.[63] P3 notes that, in the April 12 Order, the Commission appears to have assumed, and expected, that all sell offers by new entrants, even in the large unconstrained area of PJM, are either currently subject to mitigation or will be with

* * * *

[63] PPL Rehearing Request at 14.

143 FERC ¶ 61,090
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket Nos. ER13-535-000
ER13-535-001

PJM Interconnection, L.L.C.,
143 FERC ¶ 61,090 (2013)
(the "May 2, 2013 Order")

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. Lafleur, and Tony Clark.

ORDER CONDITIONALLY ACCEPTING IN PART, AND REJECTING IN PART, PROPOSED TARIFF PROVISIONS, SUBJECT TO CONDITIONS

(Issued May 2, 2013)

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G. Mitigation Period

1. PJM's Proposal

199. PJM proposes to apply the MOPR for a three-year period, or on a one-year basis, if PJM's base residual auction clears a quantity of capacity less than the installed reserve margin minus three percentage points, i.e., if the region is short on capacity.

200. PJM states that, given its proposal's focus on those resources most likely to raise price suppression

concerns, it is appropriate that the MOPR remain in effect for a longer term, as proposed. PJM asserts that applying the MOPR for only one year allows subsidized units to enter the market on a non-competitive basis, based on a temporary, coincident increase in capacity prices, or a temporary decrease in the MOPR price floor. PJM adds that the MOPR price floor is just an estimate of new entry costs and if a unit clears at that price in a single year, it does not mean that the unit will not interfere with the competitive market in subsequent years.[95]

2. Responsive Pleadings

201. Comments generally supportive of PJM's proposed mitigation term revision were submitted by EPSA, the IMM, P3, the Competitive Markets Coalition, the Pennsylvania Commission, and the Ohio Commission.

202. EPSA argues that, given PJM's proposed categorical exemptions for self-supply and competitive entry, application of the MOPR for a three-year period is appropriate. The IMM supports applying the MOPR until a subject resource has obtained an exemption of cleared three RPM auctions for three delivery years, but recommends continued evaluation of its effect on the market. P3 agrees with PJM that the revised MOPR should apply for a three-year period, given the stricter focus on resources that are most likely to pose price suppression concerns changes the circumstances under which application of the MOPR should be considered. P3 contends that the broad exemptions

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[95] PJM notes, for example, that a one-year approach could result in subsidized units perpetually bidding into RPM and then building in the first year they clear when all future risk will have been eliminated.

will sift out all but the most suspect projects, eliminating the prospect of "over- mitigation."

203. The Competitive Markets Coalition argues that for a new resource, with a useful life of several decades, one year's mitigation is a small cost and can be strategically minimized or gamed. While the Competitive Markets Coalition believes that technically, uneconomic resources should be mitigated for the life of the unit, it accepts the three- auction compromise because it will make the MOPR more effective.

204. The New Jersey Board argues that PIM's proposal to extend the mitigation period beyond a one-year term was rejected by the Commission in the 2011 MOPR proceeding and should not be re-litigated here. Specifically, the New Jersey Board notes the Commission's finding that the appropriate duration is to apply the MOPR offer floor to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost - by clearing one of the PIM capacity auctions.

205. The Maryland Commission, the Maryland Energy Administration and the Joint Consumer Advocates protest PIM's proposal. The Maryland Commission and the Joint Consumer Advocates note that the Commission rejected similar proposals in prior orders, finding that a resource demonstrates that it is needed by the market by clearing just once.

206. CPV objects to PIM's proposal, given that no developer will reasonably commence construction without the certainty that it has been accepted in RPM as a new capacity resource. CPV argues that existing generators were not required to clear in three auctions

and that, as such, PJM's proposal would unjustly discriminate against potential new entrants. CPV urges the Commission to reject PJM's proposal and thus retainPIM's existing requirement.

207. Finally, FirstEnergy asserts that in the event that the Commission directs PIM to remove all exemptions from the MOPR, then the proposal to apply MOPR until the resource clears for three separate delivery years no longer would be needed, and in that instance, should not be adopted. .

3. PJM's Answer

208. PIM argues that its proposal, narrowing the focus of the MOPR to projects that present the most concern, regarding price suppression, distinguishes the circumstances at play in the instant filing from the 2011 MOPR proceeding, in which the Commission rejected an argument, advanced by P3 and PPL, that clearing in one capacity auction is insufficient to prove that resources are economic.[96] PIM argues that narrowing the application of the MOPR, as proposed, justifies a broader application of the MOPR for a three-year period.

4. Additional Answers

209. The Competitive Markets Coalition responds to the arguments made by the Maryland Commission and the Joint Consumer Advocates that nothing material has transpired since the Commission, in the 2011 MOPR proceeding, expressly rejected PJM's prior proposal to extend MOPR mitigation through three auctions. The Competitive Markets Coalition argues that PJM's proposal in this proceeding to

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[96] *See* November 2011 MOPR Order, 137 FERC ¶ 61,145 at P 130.

extend the MOPR mitigation period is appropriate and should be accepted, given the changed circumstances presented by PJM' s proposal narrowing the MOPR.

5. Commission Determination

210. For the reasons discussed below, we reject PJM's proposal to change the duration of mitigation from one to three years. The Commission, in the 2011 MOPR proceeding, rejected proposed mitigation periods of more than one year. Specifically, in the April 2011 MOPR Order, as affirmed in the November 2011 MOPR Order, the Commission rejected PJM's section 205 proposal seeking to impose mitigation for two capacity auctions following the auction in which the resource initially clears.[97] The Commission similarly rejected P3's alternative proposal to continue mitigation until a resource clears in two base residual auctions.[98]

211. In doing so, the Commission found that applying the MOPR offer floor to a resource already determined to be economic would be unreasonable and could inefficiently discourage the entry of new capacity that is economic.[99] The Commission further found that, after clearing in the market at the offer floor price, "there is no reasonable basis for continuing to apply the MOPR," given the market's demonstration of its need for the resource.[100] The reasoned basis on

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[97] April 2011 MOPR Order, 135 FERC ¶ 61,022 at P 175; November 2011 MOPR Order, 137 FERC ¶ 61, 145 at P 122.

[98] April 2011 MOPR Order, 135 FERC ¶ 61,022 at PP 160-62, 175.

[99] *Id.* P 175.

[100] *Id.*; *see also* November 17 Order, 137 FERC 61,145 at P 131 ("[C]learing in one auction, whether the base residual auction or in an incremental auction, and committing to provide capacity for

which the Commission made its earlier decision on this matter is not altered by PJM's filing, and we are therefore not persuaded that PJM's proposal is just and reasonable.

212. We also reject PJM's argument, as supported by EPSA and P3, that increasing the duration of mitigation is warranted given that the focus of the MOPR, after the exemptions is on those entities most likely to pose price suppression concerns. Once a new resource has cleared an auction, it is obligated to begin building in order to provide capacity in the corresponding delivery year for which it has cleared. We agree with CPV's assertion that no developer would reasonably commence construction without the certainty that the project has been accepted as a new capacity resource in PJM's capacity auction. We further agree with the Maryland Commission that PJM's proposal could lead to over-mitigation by requiring a commercially operational resource to bid at an offer floor that would likely be substantially above its going-forward costs. The narrowed application of the MOPR to those deemed more likely to present price suppression concerns does not justify an unreasonably prolonged mitigation term.

H. Geographic Scope

1. PJM's Proposal

213. Under PJM's existing MOPR, the MOPR applies only to constrained Locational Deliverability

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a full year, reasonably demonstrates that a new resource is needed by the market at a price near its full cost of entry and ... it is reasonable not to subsequently apply the MOPR to such a resource.").

Areas.[101] PJM proposes to broaden this existing geographical reach to a PJM region-wide application. PJM asserts that this broader reach is appropriate, given that PJM's proposed categorical exemptions, as summarized above, are likely to exempt most projects from the MOPR.

2. Responsive Pleadings

214. Comments generally supportive of PJM's proposal to apply the MOPR on a region-wide basis were submitted by the IMM, P3, FirstEnergy, the Pennsylvania Commission, and the Ohio Commission. The IMM notes that because the potential for the exercise of market power exists throughout the PJM region, applying the protection afforded by the MOPR to the entire PJM region is appropriate regardless of whether a region is constrained. P3 states that price suppression could occur anywhere within the PJM region and must be mitigated to assure just and reasonable rates.

215. The Illinois Commission protests PJM's proposal as unsupported and otherwise unwarranted. The Illinois Commission argues that while PJM's proposed net-short/net- long proposal, as applicable to PJM's proposed self-supply exemption was developed following PJM's review of confidential LSE load data and was scaled, as appropriate, PJM's proposed region-wide application of the MOPR was presumably developed without any such data and is not scaled, as might be warranted.

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[101] *See* PJM OATT, Attachment DD at section 5.14(h)(4).

142 FERC ¶ 61,081
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

(Issued February 1, 2013)

Docket No. ER13-342-001
Docket No. ER13-343-001

KLEINMAN DECLARATION
EXHIBIT C

Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. LaFleur, and Tony T. Clark.

CPV Shore, LLC
CPV Maryland, LLC

ORDER GRANTING MARKET-BASED RATE AUTHORIZATION AND REQUEST FOR WAIVERS

1. In this order, the Commission grants CPV Shore, LLC (CPV Shore) and CPV Maryland, LLC (CPV Maryland) (collectively, "Applicants") authority to make wholesale sales of electric energy, capacity, and ancillary services at market-based rates, effective January 10, 2013. Also, as discussed below, we grant Applicants' requested waivers of the obligation to file an Open Access Transmission Tariff (OATT), to

comply with the Commission's Standards of Conduct, and to establish and maintain an Open

Access Same-Time Information System (OASIS). We also grant Applicants' requests for other waivers commonly granted to market-based rate sellers.

2. Additionally, we find that Applicants meet the criteria for Category 1 sellers in the Central, Northwest, Southwest, Southwest Power Pool, and Southeast regions and are so designated. Further, we designate Applicants as Category 2 sellers in the Northeast region; therefore, Applicants must file updated market power analyses for the Northeast region in compliance with the regional reporting schedule adopted in Order No. 697.[1]

I. BACKGROUND

3. On November 8, 2012, as amended on December 4, 2012, pursuant to section 205 of the Federal Power Act (FPA),[2] Applicants filed applications for market-based rate authority with accompanying tariffs providing for the sale of electric energy, capacity, and ancillary services at market-based rates.[3] CPV Shore

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[1] *See Market-Based Ratesfor Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at PP 848-850, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31, 305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012).

[2] 16 U .S.C. § 824d (2006).

[3] Applicants request authorization to sell ancillary services in the markets administered by the PJM Interconnection, L.L.C.,

and CPV Maryland explain that they are each constructing 725 megawatt (MW) electric generation facilities in New Jersey and Maryland, respectively, and that both plants will be located in the PJM Interconnection (PJM) market. CPV Shore states that its facility will be interconnected to transmission facilitates owned by Jersey Central Power & Light Co. and operated by PJM. CPV Maryland states that its facility will be interconnected to 230 kV transmission facilities owned by Potomac Electric Power Company (PEPCO) and operated by PJM.

4. CPV Shore states that its interconnection facilities will consist of approximately 3.8 to 4.5 miles of 230 kV line. CPV Maryland states that the PEPCO transmission line its generation facility will interconnect with is immediately adjacent to the facility. Applicants maintain that their interconnection facilities are limited, discrete facilities, constructed, used, and owned only for the purpose to accommodate connection of their generation facilities to the transmission grid. Applicants state that their interconnection facilities are radial in nature and do not form an integrated transmission grid; accordingly, they each request that the Commission grant waiver of the

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New York Independent System Operator, Inc., ISO New England Inc., California Independent System Operator Corporation, and Midwest Independent Transmission System Operator, Inc., as well as authorization to engage in the sale of certain ancillary services as a third-party provider in other markets.

requirements of Order Nos. 888,[4] 889,[5] 890,[6] 717,[7] 2004,[8] section 35.28,[9] and Parts 37[10] and 358[11] of the

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[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh 'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh 'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh 'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff' d in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff d sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[5] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh 'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049, *reh 'g denied*, Order No. 889-B, 81 FERC if 61,253 (1997).

[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh 'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh 'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[7] *Standards of Conductfor Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010), *order on reh'g*, Order No. 717-D, 135 FERC ¶ 61,017 (2011).

[8] *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs. ¶31,155 (2003), *order on reh'g*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31, 161, *order on reh'g*, Order No. 2004-B, FERC Stats. & Regs. ¶ 31, 166, *order on reh'g*, Order No. 2004-C, FERC Stats. & Regs. ¶ 31,172 (2004), *order on reh'g*, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *vacated and remanded as it applies to natural gas pipelines sub nom. National Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006); *see Standards of Conduct for Transmission Providers*, Order No.

Commission's regulations with respect to their interconnection facilities. Applicants also request additional waivers and blanket approvals commonly granted to similar applicants with market-based rate authority.

5. Applicants represent that they are Delaware limited liability companies and subsidiaries of Competitive Power Ventures Holdings, LLC (CPV). According to Applicants, CPV, through its subsidiaries, develops, owns, and manages natural gas-fired and renewable generation facilities throughout North America. Applicants state that Warburg Pincus Private Equity IX, L.P. and Warburg Pincus Equity Partners Liquidating Trust (collectively, Warburg) have a collective ownership interest of 95.2 percent of the voting shares in CPV. Applicants state that individuals own the remaining outstanding ownership interests in CPV, but none owns 10 percent or more of the voting shares in CPV.

6. CPV Shore represents that it is a wholly-owned indirect subsidiary of CPV. CPV Maryland represents it is: (1) 50 percent owned by CPV Maryland Holding Company, LLC, which is 100 percent owned indirectly by CPV; (2) 50 percent owned by Diamond St. Charles, LLC, which is (a) 95 percent owned directly by Diamond Generating Corporation (Diamond Generating), a wholly-owned subsidiary of Mitsubishi Corporation (Americas) (MCA); and (b) 5 percent owned indirectly by MIC Nebraska Inc., also a

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690, FERC Stats. & Regs. ¶ 31,237, *order on reh'g*, Order No. 690-A, FERC Stats. & Regs. ¶ 31,243 (2007).

[9] 18 C.F.R. § 35.28 (2012).

[10] 18 C.F.R. Part 37 (2012).

[11] 18 C.F.R. Part 358 (2012).

subsidiary of MCA. CPV Maryland states that MCA is a wholly-owned subsidiary of Mitsubishi Corporation.

7. CPV Shore explains that it was one of three respondents selected in a New Jersey solicitation conducted in accordance with the New Jersey Long-Term Capacity Pilot Program. Consequently, CPV Shore states that it entered into Standard Offer Capacity Agreements (SOCA) with four Electric Distribution Companies for 15-year terms.[12] CPV Shore submits that its status as a party to the SOCA is not relevant to its request for market-based rate authority.[13] CPV Shore notes that it includes the SOCA in its application "solely for information purposes" and is not requesting that the Commission address or discuss Commission jurisdiction over the SOCA in its decision on CPV Shore's request for market-based rate authorization.[14]

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[12] CPV Shore further states that the SOCA does not provide for sales of capacity or energy, but instead is a purely financial arrangement. CPV Shore explains that it will make payments to the Electric Distribution Companies when the market clearing price for capacity and energy in the PJM markets exceeds thresholds set forth in the SOCA and will receive payments from the Electric Distribution Companies when such clearing prices are below the contract thresholds. CPV Shore MBR Application at 3-4.

[13] *Id* at 8.

[14] *See* CPV Shore MBR Application at 4 n.8 ("The Commission has determined that financial contracts that do not provide for the sale of capacity or energy are not subject to the filing and reporting requirements under section 205 of the Federal Power Act. *See, e.g., Revised Public Utility Filing Requirements*, FERC Stats. & Regs. ¶ 35,541 (2001) (citing *Morgan Stanley Capital Group, Inc.* 69 FERC ¶ 61,175, at 61,696 (1994), as modified in 72 FERC ¶ 61,082, at 61,435-36 (1995) ("*Morgan Stanley*") and

8. Similarly, CPV Maryland explains that it was selected to enter into a Contract for Differences (CFD) with three Maryland Electric Distribution Companies for a 20 year term, under a Maryland Public Service Commission (Maryland Commission) program.[15] CPV Maryland submits that its status as a party to the CFD is not relevant to its request for market-based rate authority.[16] CPV Maryland also notes that it included the CFD in this application "solely for information purposes" and is not requesting that the Commission address or discuss Commission jurisdiction over the CFD in its decision on CPV Maryland's request for market-based rates.[17]

II. NOTICE OF FILING AND RESPONSIVE PLEADINGS

9. Notices of CPV Shore[18] and CPV Maryland's[19] November 8, 2012, filings were published in the *Federal Register*, with interventions and comments due on or before November 29, 2012. Notice of CPV Shore's and CPV Maryland's December 4, 2012,

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New York Mercantile Exchange, 74 FERC ¶ 61,311 (1996) (*"NYMEX"*)). However, CPV Shore is not requesting the Commission to address or discuss its jurisdiction over the contract for differences in its decisions on this request for market-based rate authority.").

[15] CPV Maryland states that the CFD does not provide for sales of capacity or energy, but instead is a purely financial arrangement as similarly described above. CPV Maryland MBR Application at 4.

[16] *Id* at 8.

[17] *See* CPV Maryland MBR Application at 4 n.7.

[18] 77 Fed. Reg. 68,766 (2012).

[19] 77 Fed. Reg. 68,768 (2012).

amended filing was published in the *Federal Register*,[20] with interventions and comments due on or before December 26, 2012. A timely notice of intervention, in Docket No. ER13-342-000, was filed by the New Jersey Board of Public Utilities (New Jersey Board) and timely motions to intervene and comments were filed by the PSEG Companies in Docket Nos. ER13-342-000 and ER13-343-000.[21]

COMMENTS

10. PSEG Companies state that their comments are to correct "mischaracterizations" of the nature of CPV Shore's SOCA and CPV Maryland's CFD.[22] PSEG Companies dispute both CPV Shore's characterization of the SOCA and CPV Maryland's characterization of the CFD as "purely financial arrangements" that are "not subject to the filing and reporting requirements under Section 205 of the Federal Power Act."[23] PSEG Companies assert that Applicants' characterizations of their respective agreements are fundamentally wrong.[24] However, PSEG Companies state they otherwise take no position on either Applicant's request for market-based rate authorization.[25]

11. PSEG Companies maintain that both the SOCA and CFD require the physical sale of capacity and

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[20] 77 Fed. Reg. 74,655 (2012).

[21] PSEG Companies are wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Inc. PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[22] PSEG Companies Motion to Intervene and Comments at 1.

[23] *Id.* at 3.

[24] *Id.*

[25] *Id.* at 5.

energy into the PJM wholesale market and that the SOCA and CFD set the price that Applicants are to be paid for those physical sales. Therefore, PSEG Companies state that the SOCA and CFD are contracts for the sale of electric energy at wholesale.[26] PSEG Companies claim the SOCA and CFD are neither "purely financial" nor similar to the contracts that the Commission has found are outside the section 205 reporting requirement.[27] In addition, PSEG Companies assert that the SOCA and CFD are not market-based rates because the rates, terms, and conditions of the SOCA and CFD were not freely negotiated or agreed to by the buyers. Finally, PSEG Companies state the rates were established by the New Jersey Board and Maryland Commission, whereas market-based rates require agreement between buyer and seller.[28]

III. DETERMINATION

12. As discussed below, we will grant Applicants' request for authorization to make wholesale sales of electric energy, capacity, and ancillary services at market-based rates and we will accept their market-based rate tariffs, effective January 10, 2013. We will also grant Applicants' requests for certain waivers.

13. As discussed below, the Commission will not address comments by PSEG Companies regarding the SOCA and CFD contracts because those comments concern matters that are outside the scope of these market-based rate proceedings.

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[26] *Id.* at 3.

[27] *Id.* at 3-4.

[28] *Id.* at 4-5.

A. Procedural Matters

14. Pursuant to Rule 214(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the notice of intervention and timely, unopposed motion to intervene serve to make the entities that filed them parties to this proceeding.

B. Market-Based Rate Authorization

15. The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[29]

1. Horizontal Market Power

16. The Commission has adopted two indicative screens for assessing horizontal market power: the pivotal supplier screen and the wholesale market share screen.[30] The Commission has stated that passage of both screens establishes a rebuttable presumption that the applicant does not possess horizontal market power, while failure of either screen creates a rebuttable presumption that the applicant has horizontal market power.[31]

17. CPV Shore states that it will own and operate a 725 MW electric generation facility located in the PJM East submarket. CPV Maryland states that it will own and operate a 725 MW electric generation facility located in the PJM market. Applicants represent that these two facilities are the only generation facilities

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[29] Order No. 697, FERC Stats. & Regs. if 31,252 at ¶¶ 62, 399, 408, 440.

[30] *Id* ¶ 62.

[31] *Id* ¶¶ 33, 62-63.

that they are affiliated with in the PJM market, or in the markets first-tier to the PJM market.[32]

18. Applicants submitted pivotal supplier and wholesale market share screens, which rely on data from Baltimore Gas and Electric Company's (Baltimore Gas and Electric) recently accepted market power analysis.[33] CPV Shore demonstrates that it passes both the pivotal supplier and the wholesale market share screens for the PJM East submarket. CPV Shore's market share screen indicates that its market share in the PJM East submarket ranges from 7.4 percent to 7.7 percent. CPV Shore's pivotal supplier screen analysis indicates that the net uncommitted supply in the PJM East submarket exceeds CPV Shore's uncommitted capacity. Accordingly, CPV Shore's submittal satisfies the Commission's requirements for market-based rate authority regarding horizontal market power.

19. CPV Maryland demonstrates that it passes both the pivotal supplier and the wholesale market share screens for the PJM market. CPV Maryland's market share screen indicates that its market share in the PJM market range from 1.9 percent to 2.3 percent. CPV Maryland's pivotal supplier screen analysis indicates that the net uncommitted supply in the PJM market exceeds CPV Maryland's uncommitted

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[32] CPV Maryland states that Diamond Generating and Mitsubishi have ownership interests in a number of companies that own generation facilities and limited interconnection facilities. Applicants also state, that except as noted in their applications, neither they nor their affiliates own or control electric generation, transmission or distribution assets or gas transportation facilities in the PJM market.

[33] *Baltimore Gas and Electric Company*, Docket No. ER 1 0-2172-007 (Nov. 1, 2012) (delegated letter order).

capacity. Accordingly, CPV Maryland's submittal satisfies the Commission's requirements for market-based rate authority regarding horizontal market power.

2. Vertical Market Power

20. In cases where a public utility, or any of its affiliates, owns, operates, or controls transmission facilities, the Commission requires that there be a Commission-approved OATT on file or that the seller has received waiver of the OATT requirement before granting a seller market-based rate authorization.[34]

21. In this case, as discussed more fully below, the Commission will grant Applicants' requests for waiver of the requirement to have an OATT on file for their transmission facilities.[35]

22. The Commission also considers a seller's ability to erect other barriers to entry as part of the vertical market power analysis.[36] The Commission requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation

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[34] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 408.

[35] A generator lead line is a transmission facility. *See* 16 U.S.C. §§ 796(23), 824(a)-(b) (2006). Applicants are subject to the requirement under Order Nos. 888 and 890 to file an OATT, or seek a waiver of the requirement to file an OATT unless and until they receive a request for transmission service. *See Milford Wind Corridor, LLC*, 129 FERC ¶ 61, 149, at P 24 (2009) (noting that the fact that the facilities merely tie a generator to the grid does not render a line exempt from the Commission's regulation of transmission facilities). *See also Evergreen Wind Power III, LLC*, 135 FERC ¶ 61,030, at P 15 n.18 (2011).

[36] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 440.

capacity development; and physical coal supply sources and ownership of or control over who may access transportation of coal supplies (collectively, inputs to electric power production).[37] The Commission also requires sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[38] The Commission adopted a rebuttable presumption that the ownership or control of, or affiliation with any entity that owns or controls, inputs to electric power production does not allow a seller to raise entry barriers but will allow intervenors to demonstrate otherwise.[39]

23. Applicants make the following representations regarding intrastate natural gas holdings: (1) Warburg Pincus Private Equity VIII, L.P., including two of its affiliated funds, Warburg Pincus Netherlands Private Equity VIII, C.V. and WP-WPVIII Investors, L.P., and Warburg Pincus Private Equity IX, L.P., indirectly own two intrastate natural gas pipeline companies, Targa Intrastate Pipeline LLC (Targa Intrastate) in Texas and Targa Louisiana Intrastate LLC (Targa Louisiana); (2) Targa Intrastate owns an intrastate pipeline that transports natural gas from Targa's Shackelford processing plant to an interconnection with Atmos-Texas; (3) Targa Intrastate also owns an intrastate pipeline that transports natural gas from a third party gathering system into the Chico System in Denton County, Texas; and (4) Targa Louisiana owns an approximately 60-mile intrastate pipeline system that

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[37] Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at ¶ 176.

[38] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at ¶ 447.

[39] *Id* ¶ 446.

receives all of the natural gas it transports within or at the boundary of the State of Louisiana.

24. Applicants also represent that neither they nor their affiliates own or control physical coal sources or control access to coal transportation, or own or control sites located within the relevant geographic market that could be used to impose barriers to market entry by other wholesale suppliers.[40]

25. Finally, Applicants affirmatively state that they have not erected barriers to entry and will not erect barriers to entry in the future in the relevant market.[41]

26. Based on Applicants' representations, and our determinations discussed below, we find that each Applicant satisfies the Commission's requirements for market-based rates regarding vertical market power.

C. Waiver Requests

1. OATT, OASIS, and Standards of Conduct

27. As noted above, Applicants seek waiver of the requirements to file an OATT, establish and maintain an OASIS, and abide by the Standards of Conduct with respect to their generator tie-lines. In support of their requests for waiver, Applicants state that their

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[40] Our authorization here is predicated on the understanding that other than the intrastate natural gas facilities identified above, Applicants and their affiliates do not own or control inputs to electric power production in other regions besides PJM. If this is not correct Applicants are directed to so notify us in the instant dockets within 30 days of the date of this order.

[41] We interpret this statement to apply to Applicants and their affiliates, and our authorizations herein are predicated on Applicants complying with this commitment. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447.

interconnection facilities do not comprise an integrated transmission system and they do not serve, and are not designed to serve, other customers.

28. Order Nos. 888 and 890 and section 35.28 of the Commission's regulations require public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to file an OATT. Order No. 889 and Part 37 of the Commission's regulations require public utilities to establish and maintain an OASIS. Order Nos. 889, 2004, and 717 and Part 358 of the Commission's regulations require public utilities to abide by certain standards of conduct.[42] In prior orders, the Commission has enunciated the standards for exemption from some or all of the requirements of Order Nos. 888 and 889.[43] The criteria for waiver of these requirements are unchanged by Order Nos. 890, 2004, and 717.[44]

29. The Commission may grant requests for waiver of the obligation to file an OATT to public utilities that can show that they own, operate, or control only limited and discrete transmission facilities and facilities that do not form an integrated transmission grid, until such time as the public utility receives a request for transmission service. Should the public utility receive such a request, the Commission has determined that the public utility must file with the

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[42] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,590; Order No. 2004, FERC Stats. & Regs. ¶ 31,155 at P 16; Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 313.d

[43] *See, e.g., Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232, at 61,941 (1996) (*Black Creek*); *Entergy Mississippi, Inc.*, 112 FERC if 61,228, at P 22 (2005) (*Entergy*).

[44] *See Alcoa Power Generating Inc.*, 120 FERC ¶ 61,035, at P 3 (2007); Order No. 717, FERC Stats. & Regs. ¶ 31,280 at PP 31-33.

Commission a *pro forma* tariff within 60 days of the date of the request, and must comply with any additional requirements that are effective on the date of the request.[45]

30. The Commission has also determined that waiver of the requirement to establish an OASIS and abide by the Standards of Conduct would be appropriate for a public utility if the applicant: (1) owns, operates, or controls only limited and discrete transmission facilities (rather than an integrated transmission grid); or (2) is a small public utility that owns, operates, or controls an integrated transmission grid, unless other circumstances are present that indicate that a waiver would not be justified.[46] The Commission has held that waiver of Order No. 889 will remain in effect until the Commission takes action in response to a complaint to the Commission that an entity evaluating its transmission needs could not get the information necessary to complete its evaluation (for OASIS waivers) or an entity complains that the public utility has unfairly used its access to

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[45] *Black Creek*, 77 FERC at 61,941.

[46] *Id* Although the Commission originally precluded waiver of the requirements for OASIS and the Standards of Conduct for a small public utility that is a member of a tight power pool, in *Black Hills Power, Inc.*, 135 FERC ¶ 61,058, at PP 2-3 (2011), the Commission explained that membership in a tight power pool is no longer a factor in the determination for waiver of Standards of Conduct. Additionally, size is not relevant to whether waivers are granted to public utilities that participate in a Commission-approved Independent System Operator or Regional Transmission Organization. *See* 18 C.F.R. § 358.1 (c) (2012).

information about transmission to benefit the utility or its affiliate (for Standards of Conduct waivers).[47]

31. Based on the statements in Applicants' applications, we find that their interconnection facilities qualify as limited and discrete. Accordingly, we will grant Applicants waiver of the requirements of Order Nos. 888 and 890 and section 35.28 of the Commission's regulations to have an OATT on file. However, if CPV Shore or CPV Maryland receives a request for transmission service, it must file with the Commission a *pro forma* OATT within 60 days of the date of the request.

32. The Commission will also grant Applicants waiver of the requirements of Order No. 889 and Part 37 of the Commission's regulations with respect to OASIS and Order Nos. 889, 2004, and 717 and Part 358 with respect to the Standards of Conduct. We note that Applicants' individual waivers of the requirement to establish an OASIS will remain in effect until the Commission takes action in response to a complaint to the Commission that an entity evaluating its transmission needs could not get the information necessary to complete its evaluation.[48] Likewise, Applicants' individual waivers of the Standards of Conduct will remain in effect unless and until the Commission takes action on a complaint by an entity that either Applicant has unfairly used its access to information to unfairly benefit itself or its affiliate.[49]

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[47] *Entergy*, 112 FERC ¶ 61,228 at P 23 (citing *Central Minnesota Municipal Power Agency*, 79 FERC ¶ 61,260, at 62,127 (1997); and *Easton Utils. Comm'n*, 83 FERC ¶ 61,334, at 62,343 (1998)).

[48] *Id*

[49] *Id* Applicants must notify the Commission if there is a material change in facts that affect its waiver, within 30 days of

2. Other Waivers, Approvals, and Authorizations

33. Applicants request the following waivers and authorizations: (1) waiver of the filing requirements of subparts B and C of Part 35 of the Commission's regulations, except sections 35.12(a), 35.13(b), 35.15, and 35.16; (2) waiver of the accounting and other requirements of Parts 41, 101, and 141 of the Commission's regulations, except sections 141.14 and 141.15; and (3) blanket authorization under section 204 of the FPA[50] and Part 34 of the Commission's regulations for all future issuances of securities and assumptions of liability.

34. The Commission will grant the requested waivers and authorizations consistent with those granted to other entities with market-based rate authorizations.[51] Notwithstanding the waiver of the accounting and reporting requirements, the Commission expects each Applicant to keep its accounting records in accordance with generally accepted accounting principles.

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the date of such change. *Material Changes in Facts Underlying Waiver of Order No. 889 and Part 358 of the Commission's Regulations*, 127 FERC if 61,141, at P 5 (2009).

[50] 16 U.S.C. § 824c (2006).

[51] We note that the Commission has examined and approved the continued applicability of the waiver of its accounting and reporting requirements (18 C.F.R. Parts 41, 101, and 141), as well as the continued applicability of the blanket authorization for the issuance of securities and the assumption of liabilities (18 C.F.R. Part 34). *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 984-985 (regarding waiver of Parts 41, 101, and 141) and PP 999-1000 (regarding blanket approval under Part 34).

D. Comments

35. We will not address PSEG Companies' comments as they are outside the scope of this proceeding, which concerns Applicants' requests for market-based rate authorization and certain waivers. As noted above, the Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal or vertical market power. PSEG Companies' comments do not address issues relevant to the Commission's market-based rate analysis or to the grant of the waivers requested by Applicants. Therefore, they are not relevant to this proceeding and will not be addressed herein.

E. Reporting Requirements

36. Consistent with the procedures the Commission adopted in Order No. 2001, an entity with market-based rate authorization must electronically file an Electric Quarterly Report (EQR) with the Commission containing: (1) a summary of the contractual terms and conditions in every effective service agreement for market-based power sales; and (2) transaction information for effective short-term (less than one year) and long-term (one year or longer) market-based power sales during the most recent calendar quarter.[52]

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[52] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh 'g and clarification*, Order No. 2001-H, 121 FERC 161,289

Public utilities must file EQRs no later than 30 days after the end of the reporting quarter.[53]

37. Additionally, Applicants must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.[54]

38. In Order No. 697, the Commission created two categories of sellers.[55] Category 1 sellers are not required to file regularly scheduled updated market power analyses. Category 1 sellers are wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate, or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been

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(2007), *order revising filing requirements*, Order No. 2001-1, FERC Stats. & Regs. ¶ 31,282 (2008). Attachments B and C of Order No. 2001 describe the required data sets for contractual and transaction information. Public utilities must submit EQRs to the Commission using the EQR Submission System Software, which may be downloaded from the Commission's website at http://www.ferc.gov/docs-filing/eqr.asp.

[53] The exact filing dates for these reports are prescribed in 18 C.F.R. § 35.lOb (2012). Failure to file an EQR (without an appropriate request for extension), or failure to report an agreement in an EQR, may result in forfeiture of market-based rate authority requiring filing of a new application for market-based rate authority if the applicant wishes to resume making sales at market-based rates.

[54] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, Order No. 652, FERC Stats. & Regs. if 31,175, *order on reh'g*, 111 FERC if 61,413 (2005); 18 C.F.R. § 35.42 (2012).

[55] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 848.

granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.[56] Sellers that do not fall into Category 1 are designated as Category 2 sellers and are required to file updated market power analyses.[57]

39. Applicants represent that they each meet the criteria for Category 1 Seller status in all regions except the Northeast region because: (1) the Applicants' facilities are located in the Northeast region and neither company owns or controls generation in any other region; (2) neither Applicants nor any of their affiliates own, operate, or control transmission facilities, except for limited and discrete generation interconnection facilities; (3) while affiliates of Applicants may own generation assets that are located in the Southwest Power Pool or Southwest regions, such assets are not attributable to Applicants because they do not own or control those assets and those assets are not (or will not be) located in the same region in which Applicants' generation assets and limited interconnection facilities will be located; (4) neither Applicant is affiliated with a franchised public utility; and (5) neither Applicant raises any other vertical market power issues.

40. Based on Applicants' representations, we designate Applicants as Category 2 sellers in the Northeast region, and Category 1 sellers in the Central,

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[56] 18 C.F.R. § 35.36(a)(2012).

[57] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

Northwest, Southwest, Southwest Power Pool, and Southeast regions. Thus, Applicants must file updated market power analyses for the Northeast region in compliance with the regional reporting schedule adopted in Order No. 697. However, the Commission reserves the right to require an updated market power analysis at any time for any region.[58]

The Commission orders:

(A) Applicants' market-based rate tariffs are hereby accepted for filing, effective January 10, 2013, as requested, as discussed in the body of this order.

(B) Waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15, and 35.16, is hereby granted.

(C) Waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of sections 141.14 and 141.15, is hereby granted.

(D) Blanket authorization under Part 34 of the Commission's regulations for all future issuances of securities and assumptions of liability is hereby granted. Applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the Applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

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[58] *Id* ¶ 853.

(E) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of either Applicant's issuance of securities or assumptions of liability.

(F) Applicants each are hereby granted waiver of the requirements under Order Nos. 888 and 890 and section 35.28 of the Commission's regulations to file an OATT, the requirements under Order No. 889 and Part 37 of the Commission's regulations to establish and maintain an OASIS, and the requirements under Order Nos. 889, 2004, and 717, and Part 358 of the Commission's regulations to comply with the Standards of Conduct, as discussed in the body of this order.

(G) Applicants are required to file EQRs in compliance with Order No. 2001.

If the effective date of either Applicant's market-based rate tariffs falls within a quarter of the year that has already expired, Applicants' EQRs for the expired quarter are due within 30 days of the date of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,

Deputy Secretary.

INTERIM REPORT OF THE PUBLIC SERVICE COMMISSION OF MARYLAND TO THE MARYLAND GENERAL ASSEMBLY

[PLAINTIFF'S EXH. NO. P391]

CASE NO.: 1:12-cv-01286

[LOGO]

PART I: OPTIONS FOR RE-REGULATION AND NEW GENERATION

DECEMBER 3, 2007

I. INTRODUCTION AND EXECUTIVE SUMMARY

This is the first in a series of Interim Reports by the Maryland Public Service Commission (the "PSC") to the Maryland General Assembly regarding the state of the electricity markets in Maryland at the end of 2007 As directed in Senate Bill 400 ("S.B. 400"),[1] Part I offers the PSC's recommendations and analysis regarding options for "re-regulating" Maryland's electricity markets and for obtaining new generation and transmission resources in our State. Additional Parts relating to stranded costs, the impact of the wholesale electricity markets on retail rates and other issues will follow in the weeks to come.

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[1] Ch. 549, Acts 2007.

The issues discussed in this Part are framed by a factual premise about which there is no ambiguity or room for serious dispute: *unless steps are taken now, the State of Maryland faces a critical shortage of electricity capacity that could force mandatory usage restrictions, such as rolling black-outs, by 2011 or 2012.* We face this crisis because Maryland sits in a highly congested portion of the regional electric transmission system (which makes it difficult to bring more power in) and because we use more electricity than is generated here. We can respond essentially in two ways: we can add more capacity, either through new generation or transmission, or we can reduce the amount of electricity we use. At the end of the day, we will need to do some of both.

We cannot, however, do nothing. Although the now-separated wholesale and retail electricity markets are structured ostensibly to create price incentives for new generation or transmission, these markets have not responded adequately or quickly enough to forestall Maryland's looming capacity shortage. These capacity shortages and transmission constraints also work to the serious economic disadvantage of Maryland consumers, who pay much higher than average prices for wholesale (and thus retail) electricity as these markets currently are structured. These higher prices make the *status quo* lucrative for existing generators rather than motivating them to spend money to build more (which would bring prices down). In our view, it is not in the public interest to continue to rely exclusively on market forces to address Maryland's reliability concerns and the high wholesale electricity prices Marylanders pay.

The data and analysis the PSC has gathered, itself and through consultants, reveal convincingly that we

do *not* have the luxury of waiting for the markets to address Maryland's reliability and pricing problems. Instead, the PSC recommends and plans to undertake a series of interventions designed to respond to these problems directly:

- *First*, the PSC will, if necessary, force an increase in the available supply of electricity, both to ensure a reliable supply and to relieve some of the upward pressure on wholesale prices. The PSC will monitor the January and May 2008 capacity auctions closely and will direct Maryland's electric utilities to enter into new, long-term contracts to induce the electricity supply in Maryland unless existing or new generators substantially increase their committed electricity capacity supply;
- *Second*, the PSC will, as part of a pending proceeding, require the utilities to implement aggressive and cost-effective demand management and energy conservation programs, consistent with Governor Martin O'Malley's EmPower Maryland initiative;
- *Third*, the PSC will rule shortly on whether, and if so how, the process by which utilities purchase electricity for Standard Offer Service ("SOS") customers could be modified to achieve better and more stable prices for ratepayers; and
- *Fourth*, the PSC will continue to expand and elevate its presence as an advocate at FERC, PJM and in other forums on behalf

of Maryland's energy future, reasonable rates, and fairness in the wholesale electricity markets.

These obviously are not the final and only actions we and others will take. The electricity markets are extremely complex, and the wisdom or economic viability of other (especially longer-term) solutions will depend on a variety of different factors and developments, many of which lie outside the PSC's control. The actions we recommend here represent important and meaningful first steps designed to counter and correct the structural unfairness of the current markets in the short- and intermediate term. We will, of course, continue to review and analyze these issues in the months and years to come and to take the steps necessary to ensure that Maryland's electricity supply is reliable and that the markets and companies treat Maryland consumers fairly.

The PSC' s consultants have analyzed the viability and economic impact of a broad array of longer-term new generation and transmission options. These analyses, which are the result of a rigorous economic analysis of different options against a set of base assumptions regarding the state of Maryland's electricity market, yielded important insights about the relative merits of different available options:

- *First*, transmission offers the highest total economic value added ("EVA") compared to the costs. New transmission affects both capacity and energy costs because it relieves the physical transmission constraints in the grid. From this perspective alone, it is the most attractive option economically. It is, however, the "option" that is the most uncertain

because its fate resides largely in the hands of other state and federal officials;

- *Second*, the nuclear case provides the highest cumulative EVA of all scenarios. Given the lead time associated with such a project, however, price benefits are not realized until 2017, about 10 years from now;
- *Third*, the addition of 1200 MW of excess power (beyond the amount needed to maintain reliability) from combined cycle gas plants provides the most substantial benefit m the short term and intermediate term;
- *Fourth*, the wind option our consultants modeled does not provide net economic benefits in either the short- or long term. Wind does, however, represent a source of clean, carbon-free power; and
- Fifth, full attainment of the EmPower Maryland Goal yields a large and positive EVA for Maryland ratepayers, greater than that of the 1,200MW of combined cycle gas option.

Our recommendations and analysis flow in large measure from comprehensive studies prepared (at the PSC's direction and under its supervision) by a team of lawyers and consultants led by the law firm of Kaye Scholer LLP ("Kaye Scholer") and the economics consulting firm of Levitan & Associates, Inc. ("Levitan"). These studies are attached to this Part and posted on the PSC's website.[2] Kaye Scholer's

[2] The PSC's website address is www.psc.state.md.us.

study on re-regulation options (the "Kaye Scholer Report") reviewed electric restructuring in Maryland and elsewhere, examined certain similarly situated states' efforts to "re-regulate," then offers and analyzes five potential "re-regulation" options, some of which could be considered and implemented in parallel.[3] Levitan conducted a detailed and rigorous economic analysis (the "Levitan Report") of the costs and benefits of options for new electricity capacity in the state, including new transmission, conservation and demand management, and various types of new power sources, such as gas, nuclear, coal, and wind. We attach both reports in full to this Interim Report so that the General Assembly and the public can review the details for themselves.

The Kaye Scholer and Levitan Reports represent only a part of the PSC's information-gathering and analytical processes, however. Over the preceding nine months, the PSC has examined a wide array of issues relating to Maryland's electricity supply, the prices Maryland residential customers pay for electricity, the wholesale markets in which Maryland's electric utility companies purchase their power supplies, and programs for low-income residents, such

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[3] It is worth noting up front that we and our consultants use the term "re-regulation" the word used in S.B. 400 more broadly than simply to mean a return to the pre-restructuring regime. Although, as discussed below, the Kaye Scholer Report briefly discusses the hypothetical possibility of returning Maryland's generation fleet to its regulated utilities, that "option" is an unrealistic and prohibitively expensive approach that both we and they ruled out quickly. Throughout both documents, we use the term "re-regulation" to encompass the range of possible PSC or legislative responses to the deregulated markets' failure to ensure reliable, cost-effective electricity for Maryland consumers.

as the Electric Universal Service Program ("EUSP"). The PSC identified a number of issues as part of its proceedings in Case No. 9099, which addressed Baltimore Gas & Electric Company's ("BGE") proposed standard offer service rate increase. The PSC also has responded to letters from Governor Martin O'Malley, who asked the PSC to study and investigate certain issues relating to the Maryland electricity markets, particularly the relationship between BGE and its parent company, Constellation Energy Group, and options for lowering the cost of electricity for low-income residents.

The PSC has utilized a variety of different methods to examine the Maryland electricity markets. The PSC has initiated numerous proceedings, including both contested case and quasi-legislative proceedings, served subpoenas and data requests, held hearings, retained outside experts, and in some cases conducted site visits. As part of the proceedings bearing on this Interim Report, the PSC:

- Conducted 13 days of contested case proceedings;
- Conducted 3 days of quasi-legislative proceedings;
- Received testimony and comments from 59 witnesses and experts; and
- Received and reviewed more than 1,200 pages of written testimony and reports.

Finally, the PSC has sought and obtained additional information regarding the wholesale electricity markets and their impact on Maryland from the Market Monitor of PJM Interconnection, Inc., the Regional Transmission Operator that operates

Maryland's electricity transmission grid (as part of a 14-state network), and PSC Staff have sought and obtained testimony from PJM witnesses in recent proceedings relating to wholesale electricity auctions. These inquiries, the only such inquiries by a state utility commission to our knowledge, have both aided the PSC's consultants and provided critical perspective on our State's short- and long-term needs for transmission and generation.

II. BACKGROUND

A. LEGISLATIVE HISTORY

During the summer of 2006, the General Assembly convened a special session to pass legislation that would mitigate a proposed 72% rate increase on residential ratepayers by BGE. Senate Bill 1 of that Special Session ("S.B. 1") capped the increase at 15% through May 2007, but allowed BGE to recover its costs of procuring the electricity that led to the increase through bonds financed (over ten years) by revenue from ratepayers. The General Assembly also imposed on BGE mandatory credits designed to offset in part the costs to ratepayers of financing the deferred costs of the rate increase. The credits consisted of (a) suspension of a portion of an administrative charge BGE collected from ratepayers as a "margin" on the SOS service, and (b) suspension of the collection of charges from rate payers to fund the decommissioning of Calvert Cliffs nuclear facilities. The legislation also attempted to reconstitute the PSC, although that effort was struck down by the Maryland Court of Appeals on September 14, 2006.[4]

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[4] *See Schisler v. State of Maryland*, 394 Md. 519 (2006).

Because of the turmoil around the 72% increase and concerns over the operation of Maryland's electricity market, the General Assembly, as part of S.B. 1, also directed the PSC to conduct a series of inquiries, including options to re-regulate the Maryland market, to review previous actions and settlements of the PSC relating to the transfer of the generating assets of the utilities as part of the restructuring of the Maryland market, and to examine methods used by the utilities to procure power. The General Assembly appropriated $750,000 for the purpose of conducting the various studies requested, including for the purpose of retaining outside expert assistance. In response, the PSC initiated limited proceedings related to the inquiries in S.B. 1 and, although it did not retain any outside expertise, issued some reports in response to S.B. 1 by the end of 2006.

During the 2007 Session of the General Assembly, and prior to the issuance of more comprehensive reports by the PSC as requested under S.B. 1, two members of the PSC resigned. Coupled with one existing vacancy, the PSC was effectively reconstituted through the appointment of three new members by Governor O'Malley.

In the 2007 Session, the General Assembly renewed its requests to the PSC originally made in 2006 in S.B. 400 and appropriated $3 million for the studies:

> The Public Service Commission shall conduct hearings, including the use of any necessary outside experts and consultants, to study and evaluate the status of electric restructuring in the State as it pertains to the current and future availability of competitive generation to residential and small commercial customers and the structure, procurement, and

terms and conditions of standard offer service for residential and small commercial customers.

In its evaluation, the Commission shall consider changes that are necessary to provide residential and small business customers the benefit of a reliable electric system at the best possible price, including options for re-regulation, if advisable, and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility.

In its evaluation, the Commission shall also consider the availability of adequate transmission and generation facilities to serve the electrical load demands of all customers in the State, pricing and physical constraints on the electrical transmission and distribution grids in the State, and options and policy recommendations to provide an adequate, safe and reliable supply of electricity at a reasonable cost to all customers in the State.[5]

In conducting the analysis described above, the General Assembly specifically directed the PSC to consider the implications of certain approaches:

- Requiring or allowing investor-owned electric companies to purchase electricity by competitive or negotiated contracts of various durations or through other appropriate methods to minimize price volatility;

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[5] S.B. 400, § 7(a)(1)-(3).

- Requiring or allowing investor-owned electric companies to construct, acquire, or lease peak- load or other generating plants and associated transmission lines;
- Providing a process, at the time bids by investor- owned electric companies for electricity supply are obtained for the standard offer service, to solicit bids for the procurement of cost-effective energy efficiency and conservation programs and services if energy efficiency and conservation programs are less expensive than electricity generation;
- Establishing a long-term goal for savings over a period of time of the total residential retail energy consumed in a year in an electric company's service territory through the procurement and implementation of cost- effective energy efficiency and conservation programs and services;
- Providing a process to allow investor-owned electric companies to obtain a portion of their electricity supply for standard offer service through the negotiation of bilateral contracts with wholesale electricity suppliers, either in conjunction with or outside of procurement through competitive wholesale auctions;
- Allowing opt-out aggregation of residential electric customer demand and small commercial electric customer demand by local governments in the

service territories investor-owned electric companies;

- Establishing an office of retail market development; and
- Requiring investor-owned electric companies to purchase accounts receiveable of electricity suppliers for residential and small commercial accounts.[6]

S.B. 400 directed the PSC to file by December 1, 2007 an interim report that, at a minimum, identifies the issues relating to options for re-regulation and discusses the costs and benefits to residential and small commercial customers of returning to a regulated electric supply market.[7] This Part, along with the Kaye Scholer and Levitan Reports, will serve as the PSC's Interim Report on these issues and, as S.B. 400 directs, the PSC will issue a final report on all matters requested by no later than December 1, 2008.

B. THE PSC'S INVESTIGATION OF RE-REGULATION

In response to the General Assembly's directive, the PSC retained Kaye Scholer, a national law firm with particular expertise in state and federal energy law and electricity markets, and a team of consultants Kaye Scholer assembled, principally Levitan.[8] Although S.B. 400 authorized the PSC to utilize an

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[6] *Id.*, § 7(b)(1)-(7).

[7] *Id.*, § 2(b)(1).

[8] The team also included SEMCAS Consulting Associates, an Upper Marlboro-based firm specializing in energy conservation and environmental consulting.

emergency procurement process, the PSC issued a formal Request for Proposals and utilized a competitive bid process that tracked Maryland's standard procurement procedure. Bids were received from numerous qualified bidders and reviewed for technical qualification and cost. The Kaye Scholer team was selected based on its superior expertise in the judgment of the PSC selection committee, which included both Commissioners and Staff, and particularly its prior representation of the California Public Utilities Commission and Connecticut Department of Public Utility Control. The committee also was impressed with Levitan, a nationally known energy consulting firm that has performed analysis for a broad array of public and private clients, including various system operators and, like Kaye Scholer, the Connecticut Department of Public Utility Control.

In addition to hiring outside expertise, the PSC has opened several proceedings related to the issues on S.B. 400 during 2007:

- In July 2007, the PSC conducted a two-day planning conference, No. PC9, to "address growth in electricity demand and consumption, the generation facilities that are currently being planned to serve those needs, the adequacy of the transmission grid and proposed additions to the grid, and steps Maryland can take to control electricity consumption."[9] Thirty-eight parties - including regulated utilities, electricity suppliers, Maryland

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[9] Notice of Planning Conference on Maryland's Energy Future, *In the Matter of the Commission's Maryland Electricity Planning Conference*, Case No. PC9 (June 8, 2007).

State agencies, local governments, other states' utility regulators, Maryland's grid operator, PJM Interconnection, LLC ("PJM") and financial services companies - submitted written comments (which are available on the PSC's website) and participated m the conference.

- As directed by the General Assembly in S.B. 400,[10] the PSC also convened a work group session in November 2007 to assist the PSC in its study and analysis of Maryland's electricity markets.[11] The PSC invited a broad array of stakeholders,[12] who provided helpful comments and insights over the course of the session.

- The PSC substantially expanded its analysis of demand-side management and energy efficiency programs. This proceeding, Case No. 9111, began in January 2007 as a request by BGE to undertake a pilot demand-response program and evolved first into a collaborative effort among the utilities, PSC Staff and the Office of People's Counsel to design and implement programs state- wide. After reviewing the initial report of the collaborative, and in light of Governor O'Malley' EmPower Maryland initiative, the PSC dramatically

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[10] S.B. 400, § 2(a)(2).

[11] *See* Notice of Workgroup Session, *In the Matter of the Commission's Maryland Electricity Planning Conference*, Case No. PC9 (November 8, 2007).

[12] *See* S.B. 400, § 2(a)(2)(ii)(1)-(16).

increased the energy savings targets it will expect the utilities to achieve.[13] The PSC held two days of hearings on the companies' proposals. The PSC also approved at tariff submitted by BGE to make permanent its original "pilot" demand-response program.

- On its own initiative, the PSC opened an investigation of the Standard Offer Service ("SOS") procurement process. Although the investigation focused primarily around the question of whether the current SOS auction process should be abandoned or modified in favor of an actively managed portfolio approach (and, if so, how to structure such a portfolio),[14] this proceeding also examined whether pricing benefits could be achieved for low-income residential customers through aggregation, whether the SOS procurement process should include bidding for energy efficiency and conservation programs, and other questions relating to the need for additional transmission and

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[13] *See In the Matter of the Commission's Investigation of Advanced Metering Technical Standards, Demand Side Management Cost Effectiveness Tests, Demand Side Management Competitive Neutrality, and Recovery of Costs of Advanced Meters and Demand Side Management Programs*, Order No. 81637, Case No. 9111 (September 28, 2007).

[14] *See* Order Initiating Proceeding, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Order No. 81563, Case No. 9117 (August 16, 2007).

> generation resources in Maryland.[15] Thirty different parties submitted more than 2,000 pages of written testimony and brought forty-one witnesses to testify over ten days of live hearings.

The PSC will issue rulings regarding demand-side management programs and the future SOS procurement process by early 2008.

III. MARYLAND'S MARKET FOR ELECTRICITY

The structure of Maryland's current electricity market derives from the Electric Customer Choice and Competition Act of 1999, which separated utilities' generating assets from their distribution and transmission functions.[16] As a result of this legislation, all Maryland-based power-generating capacity was transferred either by sale or inter-affiliate transfer from a wholly state-regulated entity, the local utility, to an unregulated power company. The net effect of this change was that the electricity previously subject to traditional rate-of-return regulation (in which the PSC set the utility's profit through a state regulatory proceeding) would now be purchased by local utilities in the federally regulated wholesale electricity market. In effect, Maryland's electricity is a commodity produced by "merchant generators," companies that sell power in a number of different markets, such as the spot market (*i.e.*, the current market) or the forward market (*i.e.*, agreements to supply electricity at a future date).

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[15] *See* Notice Initiating Phase II Proceeding, Case No. 9117 (September 25, 2007).

[16] Md. Ann. Code, Public Utility Companies Art. §§ 7-501 *et seq*.

The PSC does not regulate the wholesale electricity markets - they are regulated only at the federal level, by the Federal Energy Regulatory Commission ("FERC"). The wholesale market for Maryland power purchases is operated by PJM Interconnection, LLC ("PJM"), the Regional Transmission Operator ("RTO") that operates the power grid for 13 states and the District of Columbia. The wholesale power market is not regulated in the same manner in which the state market was previously regulated, *i.e.*, according to rate of return principles. Rather, under federal law and the FERC rules that PJM implements, the wholesale market is regulated largely through competitive market forces, limited only by whether the market is structured to deliver rates that FERC considers "just and reasonable." Federal law requires that wholesale rates be just and reasonable, but presumes that rates are just and reasonable rates if sufficient competition exists in a particular market.

The net effect of restructuring was to remove state regulators from the role of determining the bulk of the costs associated with electricity rates:

> The upshot of these federal and state innovations in electricity regulations is that state regulators, despite their continued authority over rates charged directly to consumers, have much less actual authority over those rates than they did when [*United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956)] and [*Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956)] were decided. Local utilities now obtain power largely through wholesale contracts subject to FERC's exclusive regulation, rather than through self-gen-

> erated and self-transmitted power. As a result, state regulators ordinarily must set retail rates with the wholesale rates as an established cost factor. . . FERC has exclusive jurisdiction over the wholesale rates that now drive the electric power market and, as a practical matter, largely determine the rates ultimately charged to the public.[17]

PJM not only manages the markets for wholesale electricity and its related components, but ensures the reliability of the electric system as a whole. To this end, PJM also engages in an extensive planning process, the Regional Transmission Expansion Plan ("RTEP") in which transmission projects are considered and approved to ensure the region as a whole has adequate transmission capabilities to ensure reliable electric service. Although PJM tracks projects for new generation, it may have some "last resort" ability to procure additional generation (the scope of which is unclear, and it has never been invoked).[18]

It is within this structural framework that we, with the help of our consultants, have analyzed various options for re-regulating the Maryland electricity market.

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[17] *Public Utility District No. 1 of Snohomish Co. v. Federal Energy Reg. Comm'n*, 471 F.3d 1053, 1067 (9th Cir. 2006).

[18] *See* Testimony of Michael Kormos, Case No. 9117, Phase II, at 6.

IV. ANALYSIS AND RECOMMENDATIONS

A. THE STATE AND FEDERAL ENERGY MARKETS HAVE NOT MET MARYLAND'S ELECTRICTY NEEDS

Maryland suffers from a State-wide shortfall in net generating capacity. This shortfall leads to two major consequences. The *first* impact is on price. As a general matter, rules of supply and demand dictate that prices will increase when demand exceeds supply, as is the case with Maryland's in-state generation capability. Our transmission constraints inhibit our ability to import energy to effectively match demand and supply.

The *second* major impact on ratepayers is the prospect of interruptions in service, either in the form of "load shedding," during which customers could see all or part of their electricity shut off during peak times, or statewide rolling brownouts. When the disparity between supply and demand widens enough, as PJM predicts it will in 2011-2012, prices will continue to increase and may be accompanied by a physical inability to import sufficient electricity to meet Maryland's needs. The result: PJM will unilaterally curtail existing loads, leaving Maryland consumers to pay even more money for less power.

Proponents of the *status quo* will argue that the deregulated market simply needs more time to adjust. But given the serious reliability and pricing issues Maryland faces, the threshold issue is whether "waiting for the market to work," with no guarantee that it will, is an acceptable alternative to some form of re-regulation. Under restructuring, as the General Assembly originally conceived it and as the federal

laws creating the wholesale power market contemplated, new generation would be built according to market forces rather than regulatory or legislative fiat. In our view, it would be a mistake to entrust the reliability and price stability of Maryland's electric supply entirely to these forces. Some intervention is required in the immediate future.

1. Maryland Faces A Critical Reliability Shortfall

The data and testimony the PSC has gathered in the past nine months indicate that to date, Maryland's electricity needs have not been satisfied or well-served by the "restructured" electricity markets. Maryland specifically (and the Mid-Atlantic region of the PJM footprint as a whole) faces a severe electricity reliability problem in the 2011-2012 timeframe unless two new major transmission lines are in service.

a. Major Transmission Projects Are Being Planned By PJM To Maintain Reliability.

There are major transmission projects being planned that, if built, could relieve the current constraints:

i. The TrAIL Line

The Trans-Allegheny Interstate Line ("TrAIL") is a 500-kV transmission line being developed by an affiliate Allegheny Power. As planned, this line would connect Maryland to generation sources in Virginia, West Virginia, and Pennsylvania; CPCN proceedings

are pending before the utility commissions in each of these states.[19]

This line will be able to carry as much as 2400MW of power on a single circuit, subject to access and egress circuits and the capacity of the local networks it will serve. According to PIM' s 2006 Regional Transmission Expansion Plan ("RTEP"), this project "is needed to avoid reliability criteria violations in 2011 and maintain power transfers to serve Baltimore, Washington, northern Virginia and other eastern PJM load centers." The line is expected to begin service in June 2011 and its estimated cost is $850 million. Under the rate design FERC has adopted, the costs of the TrAIL line will be socialized across the PJM region.[20]

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[19] The Pennsylvania Public Utilities Commission has received many protests against the TrAIL line. Hearings on the TrAIL application are scheduled for January 2008 in West Virginia and for February 2008 in Virginia.

[20] See PJM Interconnection, LLC, Docket EL05-121, Order 494, 119 FERC if 61,063 (4/19/07). Several parties have filed for

ii. The PATH Line.

Even if the TrAIL Line is built, PJM's reliability studies reveal that the Baltimore-Washington metropolitan area faces additional reliability violations by 2012 unless the Potomac-Appalachian Transmission Highline ("PATH"), a 765 kV line between Maryland and West Virginia, also is built. The PATH line, which is being developed by Allegheny Power and American Electric Power ("AEP"), will extend about 300 miles from the John Amos 765 kV station in West Virginia to a new Kemptown station located southeast of Frederick, Maryland.[21]

PATH would traverse both Washington and Frederick Counties in Maryland and will be able to carry as much as 5,000 MW of power on a single circuit, subject to access and egress circuits and the

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rehearing of Order 494, and FERC issued a tolling order to consider the requests for rehearing.

[21] The PATH project encompasses the first half of AEP's proposal of a 550-mile, $3 billion 765 kV line. The second part of the line (from the Kemptown Station into New Jersey) still is being studied by PJM.

capacity of the local networks it will serve. The PATH Line's estimated in-service date is June 1, 2012 and its estimated cost is $1.8 billion, which also will be socialized across the PJM region.[22] Although this line was approved by the PJM Board on June 22, 2007, AEP has not yet filed for new rates to recover the costs of the PATH project (plus incentives) or AEP has not yet filed CPCN applications with either the Maryland or West Virginia State Commissions.[23]

b. Maryland Falls Within A Newly Designated "National Interest Electric Transmission Corridor"

On October 5, 2007, the United States Department of Energy ("DOE") designated the entire State of Maryland as part of a National Interest Electric Transmission Corridor ("NIETC"). DOE made this designation under the Energy Policy Act of 2005 ("EPAct 2005"),[24] which authorizes DOE to "designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers . . . ."[25] By including Maryland within an NIETC, DOE has the authority,

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[22] FERC conditionally approved certain incentives for this line. See American Electric Power Service Corp, Docket EL06-50-000, July 20, 2006 (rehearing denied 1/22/07).

[23] A third project, the "MAAP Line," was approved by the PJM Board on October 17, 2007. The MAAP Line is proposed by PHI Holdings, Inc ("PHI") and would be a 500 kV line running from Virginia through the Delmarva Peninsula to New Jersey. The cost of MAAP Line, approximately $1.05 billion, is also expected to be socialized across the PJM region.

[24] See H.R. Rep. No. 109-215, pt 1, at 262 (2005).

[25] Id. at if 216(a)(2).

under certain circumstances,[26] to make siting and eminent domain decisions[27] that normally would fall to the PSC or other states commissions.[28] Although some state and local authorities have asked DOE to reconsider aspects of this designation,[29] the NIETC

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[26] Most notably, the EPAct allows DOE to seek, and the Federal Energy Regulatory Commission ("FERC") to issue, "backstop" construction permits when "a State commission or other entity that has authority to approve the siting of the facilities has (i) withheld approval for more than 1year after the filing of an application seeking approval pursuant to applicable law or 1year after the designation of the relevant national electric transmission corridor, whichever is later; or (ii) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible[.]"

[27] The EPAct 2005 extends to DOE "limited federal backstop siting authority (eminent domain) for electric transmission lines in areas designated by the Secretary of Energy as national interest transmission corridors" and the authority to pay "just compensation for any rights-of-way acquired by eminent domain." *See* S.R. Rep. No. 109-78, at 48 (2005).

[28] Under Maryland law, the Commission has jurisdiction to grant (or deny) certificates of convenience and necessity ("CPCNs") for the construction of overhead transmission lines over 69,000 volts. A CPCN is required before an electric company may "exercise a right of condemnation" in connection with such construction. *See generally* Maryland Code Ann., Public Utility Companies Art. § 7-207.

[29] Through the Department of Natural Resource's Power Plant Research Program, the State of Maryland sought rehearing of DOE' s designation of the Mid-Atlantic Area on the ground that the designation usurped authority properly exercised by States. The Pennsylvania Public Utilities Commission ("PAPUC"), which also has sought an injunction restraining FERC from implementing the NIETC designation for the Mid-Atlantic corridor. Other parties have introduced bills in Congress seeking

process should expedite the construction of critical transmission lines in places like Maryland that face potentially crippling transmission constraints.

c. Unless The TrAIL and PATH Lines Are Built, Maryland Faces A Substantial Capacity Shortfall

Michael Kormos, PJM's Senior Vice President of Reliability Services testified this fall that unless the TrAIL line is in service by 2012, the region's electricity load could exceed the transfer capability of the existing transmission system by 2,000 MW. The problem is compounded if the PATH line is not in service by 2012, which could cause the net load to exceed the import capability by 3,000 MW If neither line is in place on time, the regional shortfall could be as much as 6,500 MW.[30] These shortfalls are the equivalent of over ten 600 MW power plants, approximately 23% of which (or approximately 1,500 MW) would fall on Maryland alone. But this transmission shortfall is not simply a Maryland problem, it is a regional one: if Maryland, either through re-regulation efforts or market forces, increased its in-state generation to address our 1,500MW shortfall, it would remain vulnerable to load-shedding in 2012 if other states in the region failed to take action as well.

Mr. Kormos has not minced words in describing the real-world impact if these lines are not built: he testified recently that "there is the potential for

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to limit or block the NIETC designation, to ensure that states and local authorities have final say over the siting of transmission, and to deny federal eminent domain to FERC permit holders.

[30] Testimony of Michael J. Kormos, Case No. 9117, Phase II, at 3-4.

reliability problems across this region if both of the lines are not built by their required in-service dates," and, indeed, that both lines "are critical to preserve reliability in the State of Maryland as well as the surrounding region."[31] His testimony during the PSC's Planning Conference on Maryland's Energy Future was even stronger: if the TrAIL Line is not in service by 2012, the "magnitude of the overloads is downright scary," that "[t]his is not simply just a hot summer day problem," and that the grid could find itself overloaded on "any day it's a little hot."[32] A witness for PEPCO & Delmarva Power and Light, William Gausman, agreed, calling the completion of both the TrAIL and PATH lines "critical to maintaining the long term reliability and reducing persistent congestion in the Mid-Atlantic Region."[33]

It is no foregone conclusion that the TrAIL and PATH lines will be built, however. No transmission project of their magnitude has been attempted in over a decade, even longer in this part of the country, and the political opposition to these lines is organized and dedicated.[34] The ongoing failure of the market to add meaningful new transmission or capacity in the State and region manifests itself in another significant way: high wholesale (and thus retail) electricity prices for Maryland ratepayers.

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[31] *Id.* at 3.

[32] Testimony of Michael J. Kormos, PC9, July 27, 2007, Transcript at 68, 70.

[33] Testimony of William Gausman, Case No. 9117, at 2.

[34] See Testimony of Jerry Hughes, PSC Staff, Case No. 9117, Phase II, at 6.

2. Maryland's Shortfalls In Transmission And Generation Inflate Electricity Prices

When Maryland electric companies purchase power in the wholesale market, the price includes a number of separate components. Of these, three are the most significant: (a) the energy itself, which comprises the largest share of the cost; (b) congestion charges and (c) capacity charges.[35] These latter two elements are determined by the operation of the wholesale electricity markets, and particularly Maryland's location within the energy grid. Stated generally, congestion costs are driven higher by transmission shortfalls and capacity charges are driven higher by capacity shortages, which are themselves a function of available generation and transmission.

The chart below, prepared by the PSC's SOS auction consultant, Vantage Consulting ("Vantage"), demonstrates that congestion and capacity charges (and especially capacity) represent an increasing portion of the (increasing) cost of wholesale power for SOS customers:[36]

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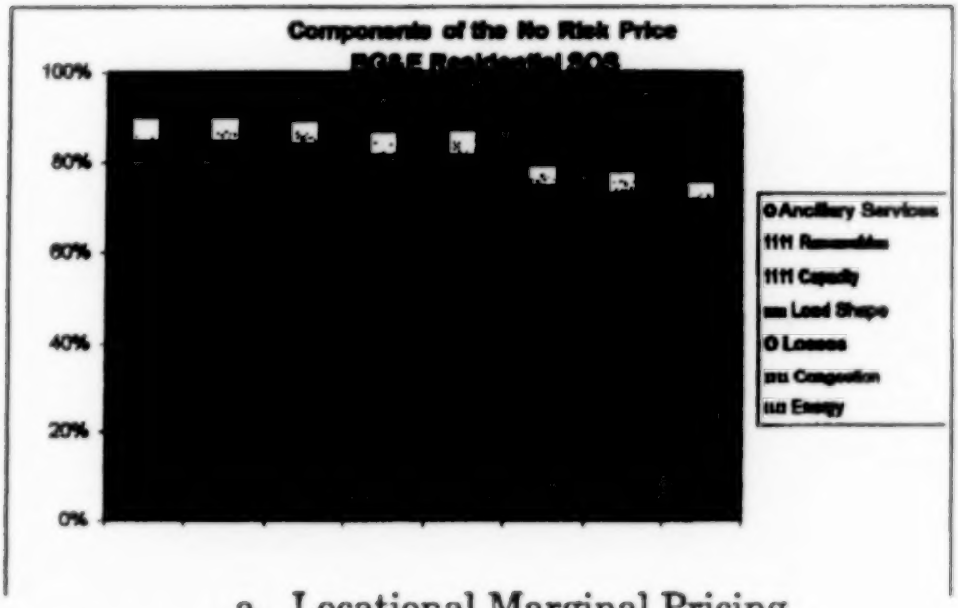
[35] The rest of the components - ancillary services, renewables, load shape and losses are relatively minor and stable.

[36] The dates indicated in this chart are the dates of the SOS auctions, not the dates the power was or would be delivered. The price allocations represent the portion of the overall "no risk" price at each auction assigned to each component.



a. Locational Marginal Pricing

Energy prices vary across the PJM footprint according to a number of factors that differentiate energy prices at different points within the system.[37] PJM, as the grid operator dispatches electricity in "merit order," *i.e.*, starting with the lowest cost generation and dispatching higher-cost generation until the electric load is satisfied. But because the highest cost or "marginal" generating unit set the clearing price for all units operating in the zone, customers pay higher prices when higher cost power must be dispatched to meet load requirements. The resulting price is called the "locational marginal price" or "LMP" for that zone.

LMPs are highest in areas of shortage or constraint. One factor that influences LMPs significantly is the extent, or lack, of transmission capability into a state or region. When transmission lines are "congested" or "constrained," *i.e.*, they cannot carry the lower cost electricity to meet demand, PJM must dispatch more

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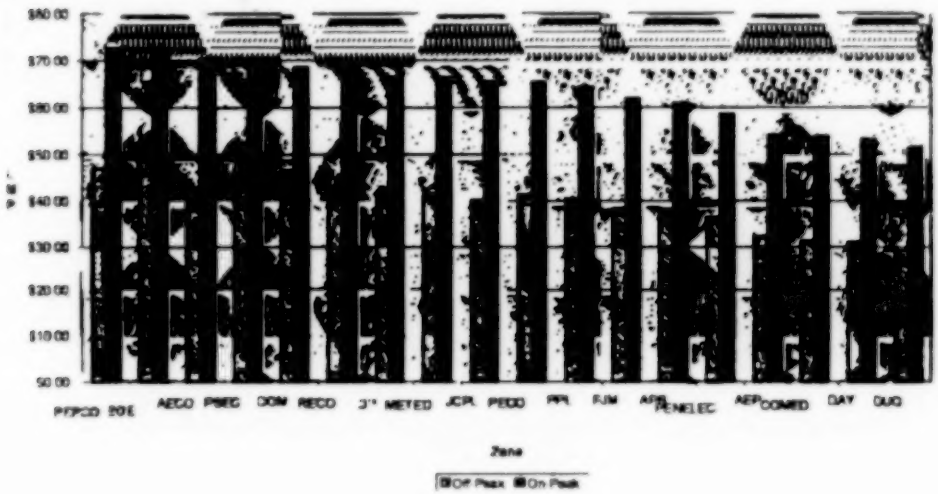
[37] *See generally* Levitan Report at 43-56.

expensive generation located in the constrained zone, which increases LMPs.

Maryland falls within the SWMAAC region, which includes the service territories of BGE and Pepco, and has a shortage of transmission capacity. This congestion, combined with Maryland's status as a net importer of electricity, requires PJM to direct less economical power plants to run in order to meet Maryland's needs. The marginal cost of power generated by those plants is considerably higher - but under the LMP model, *the high marginal cost of power from those plants sets the price for the entire region.* This out-of-merit-order dispatch creates what are referred to as congestion costs. Vantage estimates that congestion costs will add approximately $168 million to the costs of electricity for Maryland SOS customers in 2008. And in response to questions from the PSC, the PJM Market Monitor calculated the total gross (not net of any offsets) congestion cost in Maryland at approximately $1.2 billion in 2006. Net of offsets, the cost of congestion to Maryland ratepayers in 2006 was likely in the $500 million range.

As part of another analysis on which we will report separately, Levitan is currently estimating the costs of the LMPs for energy in Maryland. There is no dispute, however, that LMPs in the SWMAAC region, and therefore in Maryland, are among the highest in the PJM region, as a chart from Vantage (which highlights

the charges paid by BGE, Pepco and Delmarva Power and Light) confirms:[38]



These prices support our view that the LMP model has not worked in Maryland as its creators intended. The theory behind locational marginal pricing was to ensure that accurate price signals were sent to the market, and that "the effect of transmission capacity constraints and congestion could be explicitly included in setting the energy price each day."[39] By making the full cost of transmission constraints more transparent in market prices, participants in the wholesale markets, such as merchant generators, can determine where additional capacity is needed. Since LMPs are highest in areas that are most constrained, those high prices should, in theory, provide the economic incentives for new generators to build in constrained areas.

This has not happened. LMPs have provided higher prices and higher revenues for existing generators, but those market forces have not yielded adequate

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[38] *See also* Levitan Report at 43-44.

[39] Kaye Scholer Report at 7.

new generation inside Maryland's transmission constraints. PJM' s Market Monitor noted, in his 2006 State of the Market Report, that net revenues earned by generators were still inadequate to cover the costs of building new generation, despite the high LMPs. The result: Marylanders have paid and will continue to pay higher prices than others in the PJM region due to our higher LMPs, but no new material generation has been built in recent years, nor is significant new generation planned to come on line here anytime soon.

To generators operating in these markets, this means that the price signals sent by LMPs are not strong enough. And, in fact, FERC and PJM determined that additional price signals - generated by the relatively new Reliability Pricing Model ("RPM") described below - were needed to incent new generation. As such, Maryland ratepayers are now contributing huge payments under RPM *and* paying high LMPs, with no meaningful relief from capacity shortfalls or high prices in sight. To us, this means that the market, as currently structured, has not incented the construction needed to maintain reliable service in Maryland at reasonable prices.

b. Reliability Pricing Model

As described in detail in the Levitan Report,[40] RPM was designed to provide generators with longer-term price signals for capacity resources. These price signals are established though auctions for capacity in future planning years. Generators bid capacity for a particular "power year" (the January 2008 auction will involve bids for capacity in the June 1, 2010-May 31, 2011 timeframe), and those auctions establish that year's clearing price for capacity. PJM then makes

[40] Levitan Report at 45-51.

payments to generators bidding capacity by PJM and the load-serving entities pay for the capacity, net of certain offsets and credits.

Although the theory underlying RPM is that it will create incentives for new generation in constrained regions like Maryland's, RPM's benefits (i.e., capacity payments) are not reserved for new market entrants. Once a clearing price is established for capacity for the year in question, *all generators can receive the capacity revenues, including existing generators*. In other words, while RPM is intended to provide locational and future price signals to incent new capacity when and where it is needed, this revenue is available to all generators in the region, not just new generators. Unfortunately, this means that the *status quo* is lucrative for generators who already have plants in constrained areas, leaving them little incentive to build here - which leaves Maryland ratepayers only to hope that the price signals reach potential generators and overcome the financial and logistical barriers to entering this market that have kept them out so far.

To date, that hope appears to be in vain. RPM has resulted in significantly higher clearing prices in Maryland, but no significant new generation. According to PJM' s data, set forth the in the Levitan report, the clearing price for capacity in SWMAAC in 2009/2010 was $237/MWday, more than double the price in the PJM footprint as a whole ($102/MWday):[41]

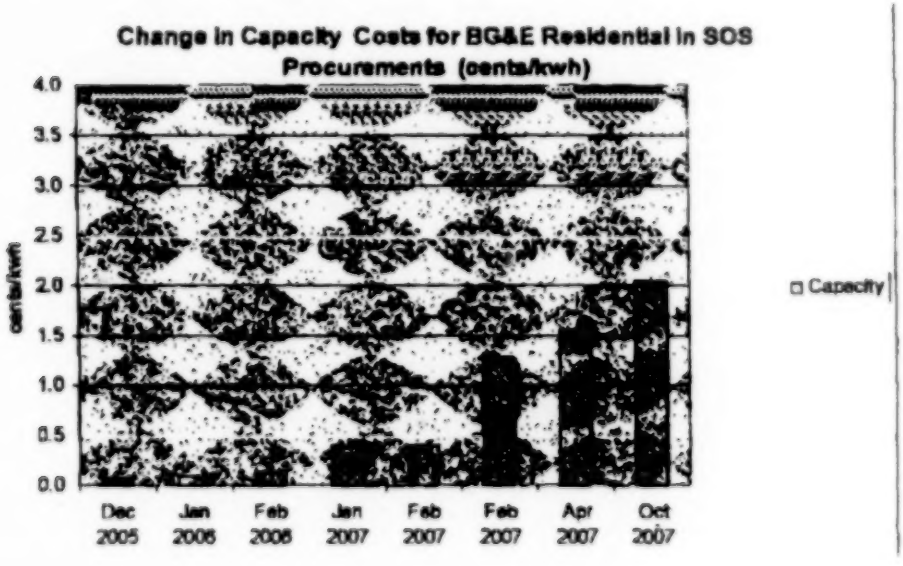
[41] *Id.* at 50.

RPM Base Residual Auction Results ($/MW-Day)

	EMAAC (Delmarva)		SWMAAC (BGE and PEPCO)		RTO (APS 07/08 & 08/09)		MAAC + APS (APS 09/10)	
	Generator Price	Load Payments	Generator Price	Load Payments	Generator Price	Load Payments	Generator Price	Load Payments
07/08	$197.67	$177.51	$188.54	$140.16	$40.80	$40.80		
08/09	$148.80	$143.51	$210.11	$180.58	$111.92	$111.92		
09/10			$237.33	$218.12	$102.04	$102.04	$191.32	$188.55

Levitan is completing a more detailed analysis of the impact of RPM on Maryland ratepayers, but we estimate that in 2008, RPM costs added $400 to $500 million to SOS residential rates, with the ultimate cost to all ratepayers much higher when commercial and industrial accounts are added in.

RPM, and the resulting increase in capacity costs, is responsible for an ever- growing portion of the increases in Maryland residential SOS rates between 2005 and the present. The percentage of the full requirements price attributed to capacity payments has increased from a barely perceptible portion of the total cost to more than 2 cents of the 10-11 cents/kwh Maryland consumers pay:



The Levitan Report describes in detail how RPM operates and the impact of changes in demand and supply on RPM auction prices.[42] As one might expect, RPM prices will decrease, all other things being equal, if new capacity resources are added faster than demand increases. Conversely, if new capacity is added more slowly than demand rises, or if plant retirements outstrip the combination of new generation and demand reduction, the capacity prices will continue to rise. And in any event, Maryland consumers will continue to pay high capacity charges until the status quo changes:

> The result of these RPM auctions indicate that the customers in Maryland will be paying higher capacity costs until (i) at least one major transmission line is completed (ii) significant in-state generation capacity is constructed or (iii) enough demand response is developed to reduce demand significantly.[43]

The question, then, is whether Maryland can wait for the market to deliver the new capacity or transmission resources it needs. We believe that the answer is an unequivocal "no."

3. Is RPM Working?

RPM is relatively new, but the auctions to date permit some preliminary conclusions.

First, as Levitan's chart (above) demonstrates, the portions of the State of Maryland encompassing the

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[42] *Id.* at 45-51.

[43] *Id.* at 51.

BGE and Pepco service territory pay significantly higher capacity charges than the rest of PJM pays.[44]

Second, it is difficult to know what signals these prices are sending. It is true that across the entire PJM footprint, some new generation and additional demand response resources have been bid into the RPM auctions. As a result, PJM believes that "[t]hrough RPM, [PJM has] retained generation that would have retired or been mothballed or been exported to other regions, plus [PJM has] attracted significant firm demand response commitments."[45] Statements by merchant generators suggest that capacity prices are causing them to consider new generation, or to reverse decisions to retire existing plants that in the absence of capacity payment were not economical. However, a closer examination of the impact of RPM in the SWMAAC portion of the PJM region, and of specific assertions made by generators, indicate that the success of RPM is an open question. Because RPM is paid to both new and existing generators, it can affect future capacity not only by encouraging new generation, but by creating incentives to invest in existing generation in order to extend the operating life of the plant. One challenge in measuring the impact of RPM lies in determining its specific impact on decisions relating to withdrawing plants from planned retirements.

An example illustrates the point. Constellation Energy Group ("CEG") announced that RPM payments have caused the company to establish 900 MW of capacity in the region that would otherwise not

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[44] *Id.* at 50.

[45] PJM Press Release, "PJM Reliability Pricing Model Attracts More Generation, Demand Response," October 16, 2007.

be available in the future. But none of this is really new: 178 MW consists of "rejuvenate[d] . . . retired generation assets in Maryland" and the rest is "further investments to extend the lives and improve the reliability and operational flexibility of about 700 MWs of older Maryland plants that might otherwise have been retired."[46] Although such actions can have the effect of creating "new" capacity at the point in time when the slated retirements are reversed, the impact may be illusory where, as in these cases, CEG had not filed for deactivation with PJM. And because these plants had not been listed for deactivation with PJM, and CEG had not notified the PSC previously that it planned to retire the plants in question, it is not possible to know with certainty (1) when or whether such deactivations were being contemplated; or (2) the extent to which capacity payments played a role if, in fact, a decision was made to extend the life of the plants.

Some witnesses testifying before the PSC have contended that the PJM interconnection queue, a list of potential and proposed generation, foreshadows an increase in generation for the PJM region. But other testimony indicates that only approximately 25% of projects on the interconnection queue are ever actually constructed, and PJM itself does not expect all projects listed in the queue to be built.[47]

A more general challenge in answering the question of whether RPM is working lies in determining what constitutes successful implement-

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[46] See Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Comments of Mayo Shattuck, Slide 8.

[47] See Testimony of Michael Kormos, Case No. 9117, Phase II, at 8.

ation. One commentator who analyzed the recent RPM auctions has questioned whether the auctions truly have increased capacity across the region by 9,000MW in the 2009/2010 planning year, as PJM claims.[48] According to Mr. Wilson, the data for the auctions for the 2007-2009 delivery years demonstrate that the growth in capacity offered into the auctions did not keep pace with the expected growth in demand. Mr. Wilson opines that only 62.8% of the capacity needed to meet the increase in PJM's reliability requirements was offered. He also fears that although PJM as whole may continue to satisfy the reliability standards, regions within PJM such as SWMAAC still face major reliability challenges. PSC staff share this concern:

> The 2007/2008 auction had a net decrease of 93MW and the 2009/2010 had a net decrease of 122.7 MW. Consequently, the net total change for installed incremental SWMAAC capacity for the three years was an increase of only 106.8MW (less than 1%). Demand response showed some promise with and incremental increase of 344.9MW, *but the SWMAAC lost a net total of 238. IMW of generation capacity during those years.*[49]

The witness for the Maryland Office of People's Counsel in the same case, Jonathan Wallach, agreed

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[48] *See* James F. Wilson, "PJM's Reliability Pricing Model (RPM): How Is It Doing, " October 2007 (based on a forthcoming report on RPM for the American Public Power Association)).

[49] Testimony of Calvin Timmerman, Case No. 9117, Phase II, at 10 (emphasis added). A portion of the reduced generation is related to the "parasitic load" associated with environmental upgrades to certain plants required by Maryland's Healthy Air Act.

that the amount of capacity for the SWMAAC region has fallen short of the minimum reliability threshold for the region in each of the three auction that have been held.[50]

Kaye Scholer also noted in its Report that in the region encompassing the BGE and Pepco territory, the capacity auction for the planning year 2009/2010 saw a net decrease in the amount of available capacity and an increase in price:

> Rather than the declining capacity prices that had been predicted and that had been experienced in other part of PJM, Maryland's capacity prices have increased with no assurances that those prices will do anything to stimulate new generation or demand response.[51]

4. Should Maryland Wait For Market Solutions To Address Capacity Shortfalls?

In our hearings, the PSC has been urged by current market participants to "wait for the market to work" before pursuing options that might involve state mandated development of new generation. These arguments rely on the theory that the market will respond eventually so long as "price signals," *i.e.*, RPM payments, are high enough for an extended length of time to make investment in new plant profitable. They correctly point out that RPM is still transitioning in - the first capacity auction for the full three-year forward period under the RPM will be held in January

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[50] Testimony of Jonathan Wallach, Case No. 9117, Phase II, at 8-9.

[51] Kaye Scholer Report at 23.

2008 for delivery in 2010-11 - and that these annual auctions should begin to provide the opportunity for new entrant power plants to enter the capacity market and for others to bid in the delayed or avoided retirements of existing units and demand response. Proponents also argue that retreating back to a rate-regulated paradigm shifts the risks associated with new construction back to ratepayers from shareholders. Proponents point to what they view as encouraging data from the RPM auctions to suggest that RPM is having its intended consequences:

> RPM appears to be starting to do what is was designed to do - promote reliability in the PJM region . . . the Commission needs to allow RPM the time to do the job it was intended to do before having ratepayers assume the potential burden of utility built generation or long term contracts.[52]

Other witnesses have argued that not only is it premature for Maryland to intervene, but also that doing so will have negative impact on ratepayers and the market as a whole. In particular, they point to the chilling effect state intervention in the market will have on the willingness of merchant generators to invest in the area:

> A major policy reason for not allowing IOUs to enter into long term contracts, or rate based generation, is the adverse effect that such contracts or regulatory compacts, have on competitive (i.e. merchant) whole-

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[52] Testimony of Glen Thomas, Case No 9117, Phase II, at 4-5. Mr. Thomas is a former Commissioner of the Pennsylvania Public Utilities Commission and current representative of power producers in the PJM region.

> sale suppliers. Utility build or contracted generation has cost recovery guarantees that merchant generators do not have. As a result, a chilling effect on new investment will occur and merchant generators will likely delay or forgo new construction and simply wait until the next utility build or buy decision. This is a path backward and will retard progressive development of competitive wholesale markets.[53]

> [I]f RPM is allowed to operate without interference from out-of-market interventions, I believe it can send the necessary long-term price signals to incentivize new generating facilities . . . the best way to ensure that RPM would not be successful, however, would be to create the perception that the regulator will subsidize new generation for the purpose of suppressing price signals to the rest of the market. This will cause prospective developers to seek higher returns for any new generation . . or they may not build at all.[54]

Maryland's investor-owned utilities have echoed this same sentiment.[55]

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[53] Testimony of Lance Muckleroy, Case No. 9117, Phase II, at 9-10. Mr. Muckleroy testified on behalf of the Retail Energy Supply Association.

[54] Testimony of Gary Sorenson, Case No. 9117, Phase II, at 3. Mr. Sorenson testified on behalf of PSEG Energy Resource and Trade LLC.

[55] See Testimony of Robert Reeping, Case No. 9117 Phase II, at 4 ("ratepayer subsidized investment could be seen as anti-competitive by the wholesale market and thus could have a

Still, RPM has not yet demonstrated an ability to incent adequate capacity to meet reliability standards, and certainly has not attracted sufficient generation to lower capacity prices, and even those who think RPM is working acknowledge that capacity will tighten before it improves.[56] We cannot help but notice, however, that while ratepayers wait for RPM to work, current and future SOS prices include payments to generators, and the price to Maryland ratepayers for "waiting" is high. If, for example, the $500 million in RPM payments currently imposed on SOS ratepayers for 2008 were directed and dedicated to the construction of new generation infrastructure in Maryland (or the SWMAAC), Maryland ratepayers could look forward to the reliability and pricing benefits from hundreds of megawatts of new generation capability. Instead, these revenues flow to existing generators without any corresponding requirement that these revenue streams from Maryland ratepayers are utilized in any way that benefits Maryland ratepayers. Funding new solutions will impose additional costs on ratepayers who, to some extent, could end up paying twice - once under RPM and then again to fund Maryland-based solutions to the problems RPM is not solving.

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chilling effect on private investment." Mr. Reeping testified on behalf of Allegheny Power.

[56] *See* Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Comments of Mayo Shattuck, Slide 7 ("These [RPM auction] results are encouraging investment in capacity, transmission and demand response initiatives, which will help meet the reliability needs of customers in the Baltimore/Washington area. However, due to long lead times for these investments to make a meaningful contribution, capacity margins are likely to continue to tighten before we begin to see sufficient development of new generation.").

It may well be that the markets will provide the new generation Maryland needs over time. There are reasonable arguments that RPM has not yet been tested, since there has not yet been a three-year forward auction. That said, Maryland faces a capacity shortfall in the near term that must be addressed, and we cannot afford to wait for market forces we cannot control. It appears, therefore, that some form of intervention will be required in the short term, before the success (or lack thereof) of RPM is established.

5. The Choice For "Re-regulation"

a. Other States Have Opted For Some Form Of "Re-regulation"

Although RPM is the subject of ongoing inquiry by the PSC, at this point it is clear that capacity prices continue to rise and contribute approximately 20% of the costs of SOS service for residential ratepayers. As noted above, ratepayers will pay hundreds of millions of dollars each year in additional costs under the federal pricing mechanism, but will receive no assurance that the money they pay will be used to address high prices, congested transmission lines and the potential for black-outs in the next 4-5 years.

In our view, it is not in the public interest to rely exclusively on market forces to deliver timely and cost-effective solutions to the serious, structural limitations in Maryland's electricity markets at this time. Maryland de-regulated in 1999 and implementation began more fully in 2000. After almost seven full years, Maryland ratepayers face among the highest capacity and locational marginal prices in all of PJM, and the prospect of draconian brown-outs in the next five years. *By these measures, Maryland is not better off than it was before deregulation.*

This experience is not unique to Maryland. As part of this analysis, the PSC asked Kaye Scholer to review the circumstances of comparable states - states that de- regulated, experienced difficulties, and then considered and implemented responses that, in some fashion, "re-regulated" the de-regulated markets. Kaye Scholer's analysis illustrates the compelling similarity between Maryland's current situation and the circumstances in these other states and provides instructive examples of interventions that did and did not work.[57]

Connecticut provides a helpful example. In that state, growing demand coupled with a lack of new generation meant that by 2009, the state faced a capacity deficit of over 600MW and needed additional generating resources by no later than 2010. Southwest Connecticut, like large potions of Maryland, sat in a transmission-constrained area and suffered from high prices. The existing generation in that portion of the state is older and inefficient, and operates pursuant to FERC-approved "reliability must-run" ("RMR") contracts that keep such units operating in order to maintain a reliable grid (but also set higher marginal prices). To the extent new generation was built, it utilized natural gas, which, based on marginal pricing there, also increased costs. In short, as in Maryland, the federal market pricing mechanisms resulted in higher costs for ratepayers, while Connecticut ratepayers faced transmission constraints and inadequate in-state generation and saw no relief on the horizon.

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[57] *See* Kaye Scholer Report at 24-63 (analyzing re-regulation efforts in Connecticut, Delaware, Illinois, New Jersey, Michigan and New Hampshire).

Similarly, in Delaware, little new generation was built after that state de-regulated. Growing demand creates higher prices, and like Maryland, Delaware faces transmission congestion. Delaware also has an older and less efficient in-state fleet of generators, which increases the LMPs ultimately passed onto ratepayers.

The Kaye Scholer Report describes how these states and others sought to respond to these challenges where the market had not. Different approaches have, of course, met with varying levels of success. But none of these states opted to rely exclusively on market forces to address their market shortcomings. Like them, Maryland cannot afford simply to wait and see.

b. The Current Market Does Not Operate Efficiently And Has Significant Barriers To Entry.

Any market-based supply and pricing paradigm is based on proper economic incentives and well functioning markets. We believe that certain elements of the current design of the wholesale electricity markets, including RPM, create competing or inconsistent economic incentives for companies that might build new generation in Maryland.

First, RPM payments to existing generators create economic incentives for them to maintain a capacity-constrained market rather than to build new generation. As the Levitan Report illustrates graphically,[58] the clearing price of capacity falls when net new capacity is introduced into a constrained region such as SWMAAC. As a consequence, existing generators in a constrained region would reduce their

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[58] *See* Levitan Report at 139-59.

revenue from existing power plants, in effect cutting their own economic throats, if they added new capacity.

Second, the current wholesale market for electricity in Maryland is inefficient. As a general proposition, efficient markets allow competition to enter readily when prices and profits rise. When barriers discourage or inhibit competition, the market is not functioning properly. The result is higher prices for buyers, excessive profits for incumbent market participants, and a continued shortage of supply.

Indeed, new generators face potentially significant barriers to entry, barriers the various pricing signals have not overcome:

- Uncertainly over the anticipated scope and expense of federal or regional regulation of greenhouse gas emissions from power plants can discourage capital investment or raise the cost of capital;

- The siting of new transmission or generation can be controversial and time-consuming; and

- The cost and availability of construction materials can be uncertain and volatile. According to Brian Chin, Vice President for Equity Research in the energy sector at Citigroup, construction costs of raw materials are rising due to global demand, including components of renewable sources such as wind.[59] Constellation Energy Group advised its investors in a recent conference call that

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[59] Generation Funding Comments, Brian Chin, Citigroup Global Markets, Inc., Case No. PC9, Slide 3.

> the cost of new construction was rising more quickly than new capacity prices,[60] meaning that the currently constrained capacity market would continue into the future.[61]

Third, the demand for electricity is generally inelastic, which means that prices for electricity can rise with little risk that suppliers will see a reduction in revenue as buyers opt not to buy. Thus, there is little incentive for suppliers to seek moderation in their prices - in a supply-constrained market, they (and their less efficient plants) are price setters, not price takers.

Finally, the PJM wholesale market is characterized by various rules and exceptions to rules, and other components that were established to address market dysfunctions and inequities. RPM, for example, is a market construct designed to solve the failure of the market to address shortfalls in capacity that LMPs, also a market construct, were (also) designed to prevent. PJM also monitors and recalibrates the "free market" in other ways - for example, by imposing price mitigation rules to prevent certain generators from exerting market power, except when a particular plant is exempt from mitigation and is allowed by PJM and FERC to exercise market power after all. The intersection of the "free market" and these mitigation

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[60] *See* Constellation Energy Q32007 Earnings Presentation, October 31, 2007, Slide 8 ("Over the past several years, rising construction and materials costs have increased the energy and capacity prices required for generators to achieve a sufficient return.").

[61] *See id.*, Slide 7 ("However, due to long lead times for these investments to make a meaningful contribution, capacity margins are likely to continue to tighten before we begin to see sufficient development of new generation.").

rules matters - the exercise of market power by plants exempt from price mitigation rules inflated wholesale prices in Maryland by $87.5 million in 2006 alone (a fact the PJM Market Monitor uncovered only in response to a special set of questions from the PSC). We are preparing a complaint with FERC to address (and, we hope, eliminate) these "market capping" exemptions.

All of these instances illustrate that the existing electricity market needs extensive tuning, supervision, and modification - in other words, is not exactly a freely functioning and efficiently operating market. Rather, the "free market" on which some advocates argue Maryland should rely features significant barriers to entry, inelastic demand and skewed market incentives that favor incumbent participants, and that market still requires monitoring and external control by a private grid operator.

c. PJM Backstop Authority

Some suggest that the PSC should rely on PJM to address capacity shortfalls. Under PJM's Tariff with FERC, PJM may have some ability to procure generation in a local area if insufficient capacity clears over a series of RPM auctions.[62] Of course, this is not a market solution - this approach simply places a regulatory solution to a market failure into the hands of a non-public grid operator rather than a public regulator. As such, we do not view this as any more a market solution than the options currently available to the PSC.

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[62] *See* Testimony of Michael Kormos, Case No. 9117, Phase II, at 6.

PJM itself views this ability (the contours of which are uncertain, and it has never been invoked) as "more in the nature of a 'last resort' than an integral tool in the planning process."[63] Regardless, we believe that continued deference to entities, whether for-profit merchant generators or an RTO such as PJM, is not in the public interest. Many of the problems noted in this Interim Report have regional implications and impacts, and a body with regional authority such as PJM may better suited to address problems on that scale (and, where appropriate, to allocate costs regionally. For that same reason, though, we do not believe that PJM is best suited to consider and implement the interventions that are in the public interest of Maryland and its citizens.

B. ANALYSIS OF OPTIONS FOR RE-REGULATION IN MARYLAND

1. Sources of Analytical Information

Three categories of sources inform the PSC' s analysis of options for re- regulation.

First, during the past several months, the PSC has conducted hearings on a variety of issues, including, among other things, the costs and benefits of requiring utilities in the state to enter long-term contracts for generation and the costs and impacts of energy conservation and demand management programs.

Second, the Kaye Scholer Report analyzes in detail attempts by other states to "re-regulate" under similar circumstances and options Maryland should, in the firm's view, consider implementing.

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[63] *Id.*

Third, the Levitan Report provides extensive modeling and economic analysis to assist in highlighting the costs and benefits of different options for new generation and capacity.

These three sets of sources allow us to offer the General Assembly a comprehensive interim "discussion of costs and benefits to residential and small commercial customers of returning to a regulated electric supply market" and our recommendations regarding the best course for Maryland in the years to come. There is a great deal more we and our consultants can and will study in the year to come, but the information we have gathered so far provides ample basis for the conclusions and recommendations that follow.

2. Goal and Purposes in Considering Re-regulation Options

Ultimately, any effort to re-regulate the Maryland electricity market has two primary objectives: *first*, to ensure that the supply of electricity and the delivery systems remain reliable; and *second*, but no less important, to obtain the best prices for Maryland ratepayers. To a large extent, solutions that address the causes of high prices also solve reliability concerns. For example, as we discuss below, adding certain types of new generation in Maryland should result in lower bills for ratepayers, but it also adds new capacity and, therefore, responds to reliability concerns.

Conversely, if Maryland's goal in re-regulating the market were merely to address reliability concerns, the minimum response will not necessarily result in the lowest possible prices. In fact, this point lies at the heart of Levitan's analysis.

In the course of modeling various re-regulation scenarios, Levitan *assumed* that Maryland would always meet minimum reliability thresholds, that the new generation options we asked the firm to consider *added to* whatever new generation was needed to maintain reliability.[64] The Levitan Report assumed that the *market* would maintain system reliability through the periodic addition of peaking plants (with low capital costs but high fuel costs) throughout the 20-year study period. Levitan assumed that roughly 220 MW in new capacity would be added in SWMAAC *each year* just to keep pace with the growth in demand. Levitan assumed that merchant generators would add these peaking units, at no direct cost to ratepayers, and so no specific rate impact was modeled. Levitan's modeling demonstrates, then, creating additional new capacity beyond that needed for reliability, or through the addition of new plant with higher capital costs but much lower fuel costs, creates the potential for rate reduction.

In determining the most prudent interventions, we have considered both the short term and long term implications of the different options. Although ensuring the reliability of the system in the short term is the first priority, an optimal solution would address both short-term reliability and reduce rates in the short- and long term.

The Levitan Report analyzes the costs and benefits of different options through the year 2027, a 20-year horizon.[65] Although many assumptions are embedded in such an analysis, most notably relative to fuel costs in the long term, it is important to model over a long

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[64] *See* Levitan Report at 106-07.

[65] *Id.* at 139-59.

horizon because many projects involve large capital outlays and take years to implement or complete (and to realize any benefits). Some options may appear to be attractive in the short term, but less so in the "out-years." Our recommendations take both the short- and long term into account.

3. The Relationship Between Transmission And Generation Influences Re-Regulation Options

As we consider options for re-regulating Maryland's electricity market, it is important to understand the interrelation between transmission and generation, and the impact that the prospect of each can have on the other. Each is a type of supply. The TrAIL or PATH lines each serve to increase available electricity in the State, and creating additional capacity, *i.e.* supply, will depress capacity prices. In fact, as discussed below, the addition of one new line could initially depress capacity prices by $65MW in SWMAAC. Because new transmission reduces capacity prices, these projects are not in the economic interests of generators who now benefit from current (high) capacity prices. And these projects could weaken the appetite of merchant generators to build new generation.

To further complicate matters, the economics of these two supply options are quite different. Under FERC rules, the costs of transmission lines like these are allocated or "socialized" across a much broader area. Also, transmission is, in general, a less expensive alternative than generation. This means Maryland would not pay the entire cost of the TrAIL line, or likely anything close to it. The cost to Maryland ratepayers of new in-state generation

equivalent to the import capability of one of the two lines would be much higher.

That said, while transmission is a cost-effective option in terms of ratepayer costs compared to ratepayer benefits, it is also the option over which Maryland regulators and policy makers have the least control. At this point, the TrAIL line falls completely outside Maryland's boundaries, and its fate rests with the regulatory processes in other states. The PATH line terminates in Maryland, but must receive the approval of other state regulators. And just as transmission can discourage new generation, the opposite is also true. That means that if we were to require utilities to procure new generation in the Maryland, we could inadvertently contribute to the case *against* new transmission:

> Commission action to stimulate new entry or reduce the demand for electricity in Maryland may have a direct bearing on both the economic and reliability rational underlying the [TrAIL] project or the other proposed projects.[66]

Because transmission is largely beyond the control of the Maryland's regulatory or legislative authority, it may not properly be considered a re-regulatory option. Nonetheless, the PSC asked Levitan to model the impact of one of the lines given the extensive advocacy for the lines by PJM and affected utilities, and its potential impact on ratepayers from both a price and reliability standpoint.

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[66] *Id.* at 128.

4. Options For Re-regulation

In this section, the PSC addresses the particular re-regulation options outlined in the Kaye Scholer Report, utilizing that analysis as well as data from the Levitan Report and the hearings the Commission has convened during the last nine months. As described on the preceding section, Maryland's current market is characterized by high prices and a potential shortfall in capacity needed to "keep the lights on" or air conditioners running, during peak hours on hot summer days in the coming years. The immediate task at hand requires us to ensure first that short-term reliability needs are met, then to establish a market or regulatory structure that achieves the lowest utility bill in the most cost-effective manner.

a. Option 1: Utility Ownership of All In-State Generation and a Return to Cost-of Service Regulation.

One option identified in the Kaye Scholer Report is "full" re-regulation - i.e ., a return to utility ownership of all generation resources in the state.[67]

A return to full re-regulation would provide the State (and the PSC in particular) with much greater control over the costs ratepayers pay for the energy portion of their electric bills. Rather than having utility rates being determined in the wholesale markets, electricity rates would once again be based on traditional rate-of- return principles.

This renewed control would come at a serious, and ultimately prohibitive, cost. Full-blown re-regulation could theoretically be accomplished by ordering the utilities to re-purchase all of the generation assets

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[67] *See* Kaye Scholer Report at 68-73.

located in Maryland (after the State condemned the plants), a direction that would undoubtedly precipitate litigation by the current owners. But even assuming there were no legal barriers, the cost would be infeasibly high: *Levitan estimates the fair market value of Maryland's generation fleet at $18-$24 billion.*[68] This estimate is admittedly a rough one, but demonstrates the order of magnitude and, ultimately, that this "option" is simply not viable. And ratepayers would feel the pain: if the utilities were to purchase these assets, rates would have to reflect the massive cost of reacquisition. Although this means that the costs associated with the wholesale market such as RPM would be avoided for any-in state generation, ratepayers would bear other costs and risks directly that they now bear indirectly or not at all, and this would have an offsetting impact on rates.

Even if full re-regulations were possible financially, it still would not completely solve Maryland's reliance on the wholesale market. Maryland still be a net importer of electricity, and thus would continue to purchase over 20% of its load in the wholesale market. Additionally, full re-regulation would not address the reliability issues discussed in detail is this report despite the huge cost of re-regulation. And rate payers would assume the future costs of all operational risks and environmental upgrades for an aging fleet of power plants.

Although the concept of re-regulation for many people is often expressed as "going back to the way it was before restructuring," our consultants' reports illustrate that this option is simply not a practical one. Aside from the fact that no other state has tried it, re-

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[68] Levitan Report at 80.

capturing the previously regulated generating fleet leaves reliability problems unsolved, is not financially practical, and would be met with legal challenges that would prevent or inordinately delay its implementation. In any event, the purchase price associated with reacquiring the state-wide generation fleet is so great that this approach could not result in any financial benefit to ratepayers, and we do not recommend any further consideration of this approach.[69]

b. Option 2: Utility-Directed Long-Term Contracts

1. The Advantages of Long-Term Contracts

As an alternative to recapturing Maryland's *existing* generating fleet, Kaye Scholer and Levitan suggest that the PSC direct Maryland utilities to procure new generation through long-term contracts. The PSC already has the authority to require utilities to buy or build generation, or to enter into long-term contracts for the purchase of electricity, so no new legislative authority would be necessary.

Under this option, utilities would enter into long term contracts for, but would not own outright, new generation in the State. These long-term agreements would induce the entry of new generation by providing the owners of new generation with a committed buyer

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[69] There is an altogether separate question about the validity of the settlements made with utilities at the time of the divesture of their generating assets in 2000, and specifically the stranded costs those settlements recognized and that ratepayers paid after divestiture. The PSC is currently investigating those settlements with the assistance of Kaye Scholer, and expects to issue its report prior to the commencement of the 2008 Session.

of the supply, the utility, backed by revenue stream from rate payers for all or a portion of the output from a power plant. This arrangement insulates the owner from any market risks - risks that external events in the market will render the investment in the plant unattractive in the market.

Although this option (and others) would require certain trade-offs, Kaye Scholer identified the following advantages:

- With long-term contracts, the State can control or influence the timing, location, and fuel type of the new generation;
- With long-term contracts, the State can reduce the cost of the investment for the generation by backing the new investment with assurances that payments will be made through utility rates, lowering capital costs; and
- Through such contracts, the State can attract new generators, enhancing competition and diversifying supply in the state.

The Levitan Report also describes the positive impact on the cost and allocation of debt and equity a utility backing project can have on a project.[70] Utility backing of a project can materially lower the costs of both debt and equity financing.

Admittedly, as Levitan points out, there are some benefits to utility-owned new generation as well.[71] For example, as with utility-backed projects, utility-owned

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[70] *See* Levitan Report at 77-78.

[71] *See id.* at 80-81.

and financed projects will reduce the cost of equity and debt because of the utilities' ability to ensure cost recovery from ratepayers. And as with utility-directed generation, the timing and scope of utility-owned generation can be subject to greater state input and oversight than merchant generation.

However, Levitan and Kaye Scholer both identify risks with the utility- ownership option as well, such as the lack of current expertise resident in the utilities in managing construction projects and operating the plants.[72] Having divested their generating assets, the expertise to construct and run power plants no longer resides in the utilities and would need to be reestablished. In the survey of other states in similar circumstances to Maryland's set out in the Kaye Scholer Report, states have largely taken the utility-directed approach rather than compelling utilities to re-enter the realm of plant ownership. In addition, and importantly we believe, outright ownership places all long-term operational and market risk on the utility, and therefore the ratepayers.

Both Reports identify a number of different options for long-term contracts. These include options for capacity only, the approach taken by Connecticut. In that case, the state issued RFPs and selected four projects totaling 787MW of new capacity, including a new 620MW gas fired combined cycle base load plant.

Delaware directed Delmarva Power & Light to issue RFPs for the purchase of 400MW of new generation under a long term power purchasing agreement, to be operational by 2013, although the Delaware

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[72] *See id.*; *see also* Kaye Scholer Report at 73-74.

Commission recently rejected the proposals because none of the bidders met the state's requirement.[73]

Given the information presented in both Reports, and the testimony received in hearings before the PSC, particularly Case No. 9117 Phase II, we conclude that the best alternative for ratepayers appears to be directing utilities to issue RFPs for long- term contracts for some combination of new in-state capacity, energy, or both. This option appears to offer many of the same benefits as utility-owned new generation, but minimizes the risks to ratepayers associated with ownership.

b. Analysis Of The Costs And Benefits Of Long-Term Contracts For New Supply In Maryland

In this section we address the extensive analysis performed by Levitan in modeling supply options for Maryland. To the extent the options involve new generation, it was assumed that the new generation would involve a long-term purchased power arrangement ("PPA") with utilities in the state. The Levitan Report details the extensive inputs and assumptions used to conduct the modeling and those will not be repeated here. The PSC notes, however, that in order to respond to the General Assembly on time, the PSC could not conduct, and did not request, that Levitan perform a full "integrated resource plan," in which an optimal mix or combination of technologies is employed. Rather, the Levitan Report provides meaningful comparisons among and between various choices of supply.

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[73] Kaye Scholer Report at 74.

With the direction of the PSC, Levitan developed a base case or "reference case" against which all scenarios were compared for each cost/benefit analysis:

> The *Reference Case* represents Maryland's existing generation resource mix, transmission infrastructure, and a limited level of demand side management ("DSM"), but no new initiatives to foster an increase in generation supply or a decrease in electricity demand. For the *Reference Case*, we have incorporated about one-fourth of the total DSM objective associated with Governor O'Malley's "15 by 15" Initiative - a 15% reduction in per capita energy demand by 2015 - which the State may be able to achieve with existing programs. Because the *Reference Case* limits resource additions to peakers through 2027, it does not include new high-voltage transmission "highway" projects, new combined-cycle or coal plants, new in-State renewable energy resources (e.g., wind), or a new nuclear plant. In terms of renewable energy, we assumed in the *Reference Case* that each Maryland utility will continue to comply with Maryland's renewable portfolio standard ("RPS"), but will meet only the mandatory solar component through photovoltaic additions within Maryland.[74]

One assumption that was the subject of extensive discussion prior to the commencement of the analysis related to the role of conservation and demand-side

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[74] Levitan Report at 1-2.

management in the base case. Because the modeling took place after Governor O'Malley announced the EmPower Maryland Initiative, the PSC believed that some incremental energy savings should be built into the reference case. The PSC has developed overall targets for utilities based on the 15% per capita savings contemplated by the "15 by 15" savings in the EmPower Maryland Initiative. But for the base case, Levitan assumed that the utilities would achieve 25% of the 8,500 GWhs in savings needed to meet the EmPower Maryland goal.[75]

After constructing the Reference Case, Levitan modeled the following one-off scenanos:

> • *Optimum Mix* - We substituted more efficient but more expensive combined cycle generation plants for one or more peakers over the planning horizon whenever market conditions arrant. We assume that the addition of a combined cycle plant would require a long-term contract with Maryland's utilities.
>
> • *Coal* - We added a 648 MW supercritical pulverized coal plant with state-of-the-art pollution controls in lieu of an equivalent amount of peakers. We assume that the new coal plant would achieve commercial operation in 2015 under long-term utility agreements authorized by the PSC.

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[75] The 8,500 GWh savings figure represents the "low case" estimate of the energy savings necessary to achieve the EmPower Maryland goal. This "low case" is based on the Power Plant Research Project's load forecast assumptions. The "high case," based on historical growth assumptions, would require approximately 17,936 GWh of total savings by 2015.

• *Nuclear* - We added a new 1,600 MW reactor unit at Constellation's Calvert Cliffs facility. We assume that the new nuclear plant would achieve commercial operation in 2017 under long-term agreements with Maryland's utilities.

• *15 x 15 DSM* - We added ambitious conservation and load management initiatives in the form of utility-sponsored programs and regulatory mandates. These programs reduce Maryland's dependence on new peakers to ensure adequate supply but are primarily oriented to achieving more efficient use of energy around- the-clock. We assume that the utilities' earnings are decoupled from DSM programs so that they have an incentive to promote load reduction. We have quantified total program costs, including residential and commercial costs that are independent of utility programs in order to achieve the full "15 by 15" Initiative.

• *Transmission* - We added one new backbone or "highway" transmission project that will begin serving Maryland in 2015, thereby alleviating congestion and promoting grid reliability throughout the region. The addition of a major new transmission project would lessen Maryland's dependence on new peakers from 2015 throughout the remainder of the study horizon. Under transmission ratemaking principles approved by the Federal Energy Regulatory Commission, the cost of new transmission would be apportioned among ratepayers in Maryland and ratepayers elsewhere in PJM.

> • *Wind* - We added 500 MW of new wind turbines, both onshore and offshore by 2012. Because wind is an intermittent generation resource, only about one-fifth of the total nominal installed capacity can be treated as dependable capacity. Therefore the wind turbines only slightly reduce the need for new peakers to maintain grid reliability. Like the other resource options that comprise the Alternative Cases, we assume that the addition of new wind generation would require long-term agreements authorized by the PSC between wind developers and Maryland's utilities.
>
> • Overbuild - We added a generation reserve surplus of 1,200 MW beginning in 2011. We assume that the reserve surplus will consist of new combined cycle plants in Maryland and will be sustained through the study horizon. Both the 1,200 MW of combined cycle plants as well as gas turbine peakers added later to the resource mix would require long-term contracts with the utilities.[76]

The results of the modeling are most succinctly summarized in the following charts, which show the "Economic Value Added" ("EVA") above (or below) the Reference Case by each of the one-off options over the 20-year forecasting horizon.[77] The EVA calculation essentially reflects the present value of the total costs and benefits of the options compared to the reference

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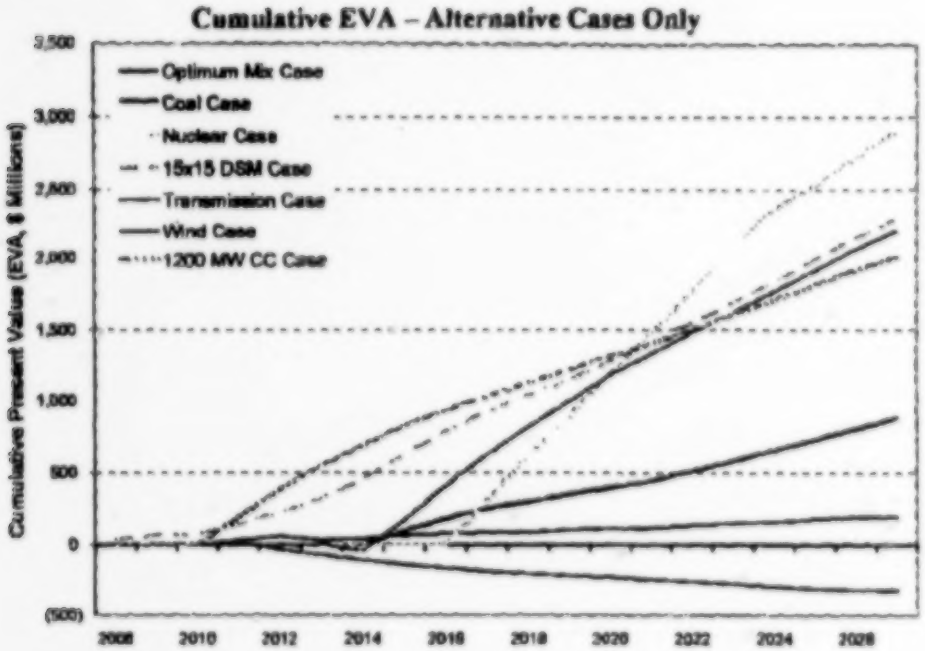
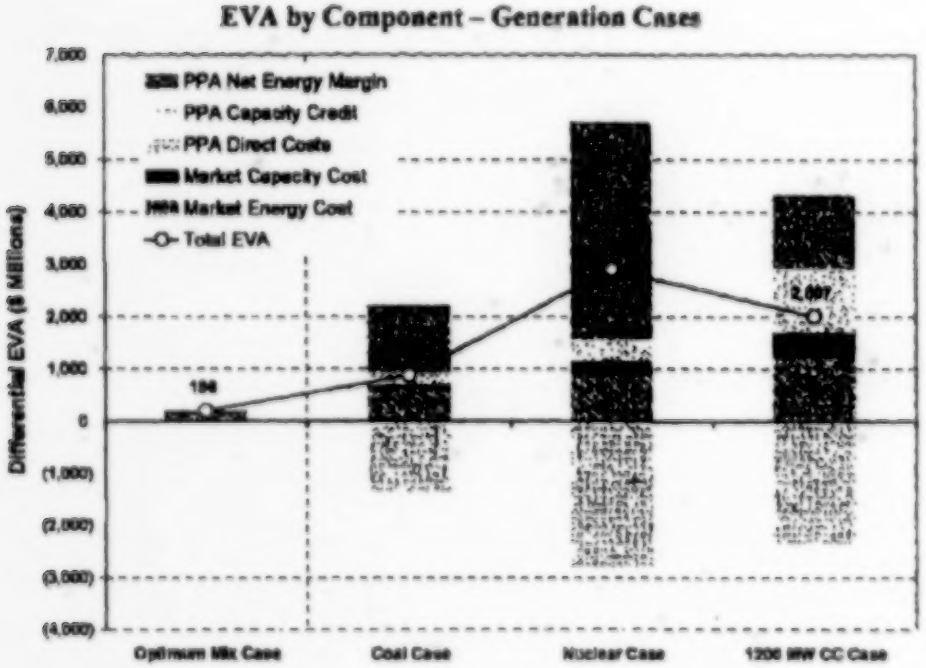
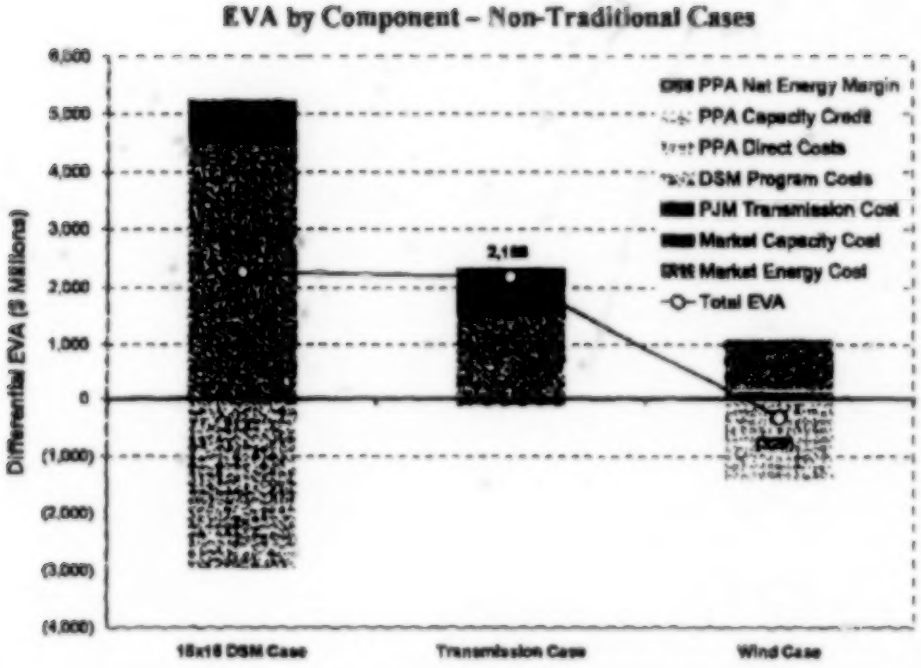
[76] *Id.* at 2-3.

[77] *See id.* at 105-59 for Levitan's complete analysis; these chart appear at 148-50.

case over the next 20 years, and the results are striking:







Several critical points emerge from Levitan's analysis.

First, as noted earlier, transmission offers the highest total EVA compared to the costs. New transmission affects both capacity and energy costs because it relieves the physical transmission constraints in the grid. From this perspective alone, it is the most attractive option economically. It also is the "option" that is the most uncertain because its fate resides largely in the hands of other state and federal officials. Also, transmission is cost-effective in large part because it permits the importation of "cheaper" electricity, *i.e.*, electricity generating from coal burning plants west of the major constraints in Maryland. Because, as stated earlier, Maryland cannot "re-regulate" transmission, transmission should be viewed as an external factor that influences, or can be influenced by, decisions on other options.

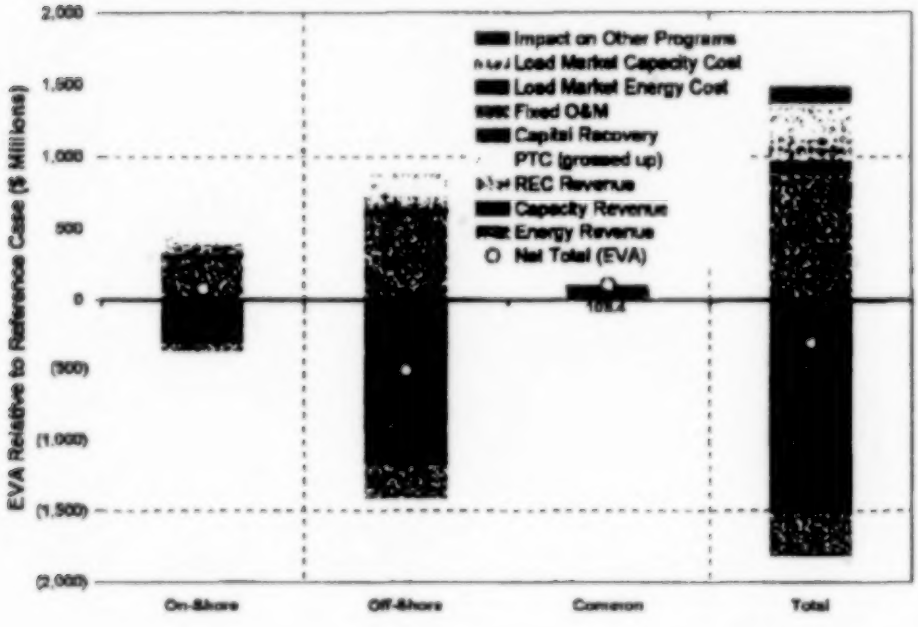
Second, the nuclear case provides the highest cumulative EVA of all scenarios. Given the lead time

associated with such a project, price benefits are not realized until 2017, about 10 years from now. Nonetheless, as the cumulative EVA figure from the Levitan Report illustrates, new nuclear generating capacity provides a rapid, substantial and sustained benefit to Maryland ratepayers unmatched over the 20-year horizon by any other option.

Third, the addition of 1200 MW of excess power (beyond the amount needed to maintain reliability) from combined cycle gas plants provides the most substantial benefit in the short term and intermediate term. In the long term, the benefits would be eclipsed from the nuclear option, but through 2020, the 1,200 MW CC option is the best alternative from an EVA perspective.

Fourth, the wind option that Levitan modeled does not provide net benefits in either the short- or long term. As the Levitan Report details, onshore wind projects can be a net benefit to ratepayers, but the relative costs and benefits of offshore wind are not positive. Levitan modeled a scenario that involved 300 MW of offshore wind and 200 MW of onshore wind. The projects modeled have minimal impact on energy and capacity prices - but given their cost, the EVA is a negative $329 million over 20 years. Levitan's figure illustrates the differences in the EVAs for onshore and offshore wind projects:

Breakout of Off-Shore, On-Shore Effects



Fifth, full attainment of the EmPower Maryland Goal yields a large and positive EVA for Maryland ratepayers, greater than that of the 1,200MW of combined cycle gas option. Levitan estimates that costs for what it describes as an "extremely aggressive" and unprecedented level of conservation[78] are higher than the costs of the gas-fired generation, but that these costs are more than offset by the overall reduction in energy consumption and therefore energy costs. This point is made in the following table from the Levitan Report, which shows the estimated residential ratepayer impact in the BGE territory from achieving the full EmPower Maryland objective. For the DSM option, electric rates increase as a result of the initiative compared to the Reference Case and all the other options. But by virtue of the overall

[78] *Id.* at 126.

reduction in consumption, bills go down and ratepayers benefit materially from conservation:

Typical Residential Annual Bill – BGE

Case	Year	Annual Energy, kWh	Annual Bill, $	% Change from *Reference Case*	Average Price, $/kWh	% Change from *Reference Case*
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Optimum Mix	2015	11,810	$1,928	*-0.70%*	$0.1631	*-0.70%*
	2020	11,664	$2,279	*-0.22%*	$0.1954	*-0.22%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Coal	2015	11,810	$1,891	*-2.51%*	$0.1601	*-2.51%*
	2020	11,664	$2,256	*-1.24%*	$0.1934	*-1.24%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Nuclear	2015	11,810	$1,940	*0.00%*	$0.1642	*0.00%*
	2020	11,664	$2,100	*-8.07%*	$0.1800	*-8.07%*
	2010	11,924	$1,753	*-0.49%*	$0.1470	*1.61%*
15x15 DSM	2015	9,896	$1,833	*-5.50%*	$0.1852	*12.78%*
	2020	9,896	$2,184	*-5.25%*	$0.2187	*11.68%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
Transmission	2015	11,810	$1,828	*-5.78%*	$0.1548	*-5.78%*
	2020	11,664	$2,143	*-6.18%*	$0.1837	*-6.18%*
	2010	12,175	$1,760	*-0.07%*	$0.1446	*-0.07%*
Wind	2015	11,810	$1,953	*0.67%*	$0.1654	*0.67%*
	2020	11,664	$2,292	*0.35%*	$0.1965	*0.35%*
	2010	12,175	$1,762	*0.00%*	$0.1447	*0.00%*
1200 MW CC	2015	11,810	$1,870	*-3.61%*	$0.1583	*-3.61%*
	2020	11,664	$2,209	*-3.30%*	$0.1893	*-3.30%*
	2010	12,175	$1,634	*-7.22%*	$0.1342	*-7.22%*
Low Fuel	2015	11,810	$1,713	*-11.69%*	$0.1450	*-11.69%*
	2020	11,664	$1,920	*-15.91%*	$0.1646	*-15.91%*
	2010	12,175	$1,796	*1.98%*	$0.1476	*1.98%*
High Fuel	2015	11,810	$2,120	*9.28%*	$0.1795	*9.28%*
	2020	11,664	$2,506	*9.75%*	$0.2149	*9.75%*

c. Conclusions Regarding Long-Term Utility Contracts for New Generation

The analyses by Levitan and Kaye Scholer combine to create a compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a "re-regulation" option that we believe should be pursued and that we intend to pursue.

Several factors support this view. *First*, Levitan's initial economic modeling shows that the addition of new generation in the state can serve to lower costs for ratepayers. In cases of new generation, cost reductions to ratepayers flow from the net benefits from lower energy and/or capacity costs after new supply is introduced. *Second*, the Kaye Scholer Report explains how states that are more advanced in their approach in addressing supply inadequacies have adopted this approach. We believe this approach balances competing trade-offs for the benefit of ratepayers and does so at a reasonable cost.

Although transmission additions such as the TrAIL line would address reliability and cost issues as well, the prospect that even one of the lines will be completed in the 2011-2012 timeframe is uncertain at best. While the testimony from utility representatives was optimistic if not vague, several facts suggest the lines may well be delayed or not built at all. For the same reason that we find it unsatisfactory to wait for the market to solve Maryland's challenges, we find as well that we cannot hope or wait for the TrAIL or PATH lines to solve them. The prospect for new, material transmission expansion such as the TrAIL or PATH lines is uncertain enough that, in our view, Maryland must take action on its own to address the reliability issues we face and secure the lowest possible rates for ratepayers.

Although we reach our conclusions regarding long-term contracts on our own, parties appearing before the PSC in recent cases also have urged us to prepare for the prospect of procuring energy for reliability through long-term utility contracts. In Case No. 9117, several parties - including the Maryland Energy Administration, the Office of the People's Counsel, and

Staff for the PSC - agreed that the State must prepare for the potential shortfall in capacity for the 2011-2012 timeframe by directing the utilities to develop RFPs for new generation that could be issued by the summer of 2008. This testimony bolsters the views of our consultants and adds to our confidence in this approach.

We plan to implement the long-term contracting strategy over the next six months. Before directing the utilities to enter contracts, the PSC will monitor and evaluate the next two RPM auctions to be held by PJM for the planning years 2010-2011 and 2011-2012, which will take place in January 2008 and May 2008, respectively. We will determine if the trends of the previous auctions, in which the capacity offered was insufficient to meet reliability standards, have reversed and, therefore, whether the market has responded adequately for these two critical years. Because the results of both auction will not be known until May 2008, only 36 months before reliability margins are at risk, we will devote the intervening time to a more in- depth study of the specific components of the contracts we would direct the utilities to enter so that we could direct the utilities to issue Requests for Proposals for these contracts immediately after the May 2008 auction, if necessary.

Given that the prospect of procuring capacity in the short term through utility contacts is already under consideration by the PSC in Case No 9117, we believe that the prudent approach is not simply to seek the amount of capacity needed to ensure reliability criteria are met, but to also seek a more extensive 'portfolio, as Levitan' s analysis suggests. However, as discussed above, even the reliability shortfall is significant - approximately 1,500 MW for Maryland

and 6,500MW for the region - and we may determine that the utilities will need to procure substantial additional capacity to satisfy Maryland's reliability needs. PSC staff witness Jerry Hughes testified that "[i]t is likely in the long term, two generating stations of [600MW each] will be required to satisfy the growing electricity demand in Maryland."[79] We will err on the side of requiring more than the minimum amount of additional capacity, although we will endeavor to strike the appropriate balance.

Beginning in January or February 2008, then, the PSC will direct Maryland's Investor Owned Utilities to begin preparing Requests for Proposal for long-term power contracts to be issued, if necessary, in May 2008, under the supervision of the PSC. In the meantime, the PSC will determine the appropriate scope of the Requests for Proposal, the types of contract(s) the utilities will be required to seek, the amount of generation they will be required to procure, fuel type, and other key variables.

c. Option 3: State Power Authority

Some states have considered or enacted legislation to create state power authorities. The State of Illinois, for example, recently enacted legislation to establish a state power authority with a broad range of responsibilities such as developing procurement plans for default service, constructing new generation in the state, and selling power to various groups of consumers in the state such as government aggregators or rural electric cooperatives. The Illinois

[79] Testimony of Jerry Hughes, Case No. 9117, Phase II, at 11.

power authority is also charged with promoting energy efficiency programs.[80]

Kaye Scholer identified a number of functions that could be performed by a state power authority, including:

- Analysis of available and prospective resources necessary to meet Maryland's needs (*i.e.*, integrated resource planning);
- Aggregation of efficiency or demand management resources;
- Procurement and/or development of prospective generation sites for resale to prospective generators;
- Stimulation ofrenewable energy projects in the state;
- Contracting directly for all or part of the utilities' load in the state; and
- Direct ownership of generating facilities to satisfy all or part of the utilities' load in the state.[81]

The Kaye Scholer report identifies some advantages to some of these proposals, particularly as it relates to the development of new generation in the state.[82] For example, a state power authority can have significant cost advantages over a utility when it comes to constructing and operating a power plant. A state-operated plant would pay no taxes, would have lower costs of capital and not have equity investors requiring

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[80] *See* Kaye Scholer Report at 49 and 81-83.

[81] *Id.* at 81-83.

[82] *Id.*

a return on equity capital. It also could direct the development of certain types of new generation that the market may not be ready to fully embrace.

On the other hand, all the risks attendant with ownership and operations, including the investment risk associated with the power plant and market risks, to name just two. This approach to re-regulation moves even beyond the State requiring the utilities to enter into long-term contracts or to build new plants - it places the State squarely into the energy business.

When it comes to the construction or development of new generation, there may be potential advantages to placing the State in a role that is beyond regulation, *i.e.*, in the business of owning and running power plants. However, we believe that this approach requires further analysis and study. With respect to most of the other functions of a state power authority identified by Kaye Scholer or enacted by Illinois, however, most of those functions are currently with the statutory authority of the PSC.

d. Option 4: Integrated Resource Planning

The Kaye Scholer Report identifies the reinstitution of integrated resource planning ("IRP") as one type of re-regulation.[83] As described in the Report, the IRP process was a staple of the pre-restructuring, regulated paradigm, in which utilities engaged in long-term planning so that resources would be available to meet needs in the short- and longer terms. In those days, the State had an active role in overseeing the plans and their implications.

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[83] *Id.* at 83-85.

Restructuring has largely disintegrated that process. Since de-regulation, utilities have largely left the planning and development of new generation to the market, i.e., merchant generators. Testimony before the Commission clearly indicated that utilities also view PJM, not the State, as the party responsible for the planning needed to ensure a reliable grid.

Because, as discussed above, we cannot leave the planning for Maryland's energy future entirely in the hands of market forces, we believe that reinstituting and reinvigorating the IRP process is a critical component of any re-regulatory initiative. Planning the appropriate mix of cost effective resources - transmission, conservation and new generation - should be one of the core functions of the PSC. To this end, the PSC has initiated plans to develop a dedicated in-house IRP unit. The exact staffing, budget, and consulting assistance needed to re-establish an IRP process is still being developed.

e. Option 5: Aggressive Efforts To Shape PJM's Wholesale Markets

As this report describes, and as Kaye Scholer confirms, wholesale market policies significantly impact the prices the residents of restructured states pay for power.[84] Under any realistic re-regulation scenario, Maryland will continue to rely on the wholesale market for a large portion of its electricity. It is, therefore, critical that the state play as an active and aggressive role as possible in the development of those policies. As Kaye Scholer points out, the state of Connecticut pursued this approach with some success.

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[84] *Id.* at 85-87.

The PSC has already taken several steps on this front. The PSC has hired new senior staff with direct experience in wholesale markets and FERC proceedings. In addition, the PSC has asked Levitan to perform a detailed analysis on the impacts of LMP and RPM on Maryland ratepayers beyond that performed by the PSC in-house. And finally, the PSC has retained Kaye Scholer to analyze legal options relating to challenges to various aspects of the wholesale market design and, if necessary, to assist the PSC in pursuing them.

In summary, we agree that active and vigorous engagement at the federal level is a vital part of any re-regulatory process, and that the more passive, market-based approach of the PSC on such key issues in the past must end. We note that the players who stand to benefit most in such proceeding, such as the merchant generators, have broad and deep representation before FERC. We agree that the State must take steps to level the playing field, and that process has already begun at the PSC.

V. CONCLUSION

This represents the Interim Report of the Maryland Public Service Commission to the General Assembly pursuant to S.B. 400. The PSC will continue to examine these and other possible "re-regulation" options in the coming year and will submit its Final Report on these issues no later than December 1, 2008.

FINAL REPORT
OF THE
PUBLIC SERVICE COMMISSION OF MARYLAND
TO THE
MARYLAND GENERAL ASSEMBLY

OPTIONS FOR RE-REGULATION AND NEW GENERATION

[LOGO]

Maryland
Public Service Commission

December 10, 2008

Pursuant to §2(b)(2), Chapter 549, Acts 2007

I. INTRODUCTION AND EXECUTIVE SUMMARY

This is the Final Report of the Maryland Public Service Commission (the "Commission" or "PSC") to the Maryland General Assembly, as directed in Senate Bill 400 ("S.B. 400").[1] In S.B. 400, and in response to the growing public and legislative belief that deregulation had not served the public interest, the General Assembly directed the Commission to study and report on whether and how Maryland might "re-regulate" its electricity markets. The Commission's Interim Report, Part I, filed on December 3, 2007, identified and analyzed various "re-regulation" options, then modeled the economic impact of those options in light of market conditions at that time. This Final Report details the Commission's work since the Interim Report, analyzes the current state of the energy markets, updates the prior economic analysis of the various "re-regulation" options, and offers a series of recommendations regarding the best course for taking and maintaining control of Maryland's energy future.

The updated analyses, performed again by Commission consultants Kaye Scholer LLP ("Kaye Scholer") and Levitan & Associates ("Levitan"),[2] sought to reflect not only the evolution of the fuel and electricity markets since the Interim Report, but also to incorporate now-available information regarding demand-

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[1] Ch. 549, Acts 2007.

[2] Kaye Scholer's and Levitan's full reports and analyses are included with the copies of this report distributed to the General Assembly and available at the Commission's website, www.psc.state.md.us. The report tabbed as "Task 2 Report" will be referred to as "Kaye Scholer report" and the report tabbed as "Task 3 Report" will be referred to as "Levitan Report."

side management and energy efficiency programs, new on- and off-shore wind generation projects, and Maryland's solar initiative. In response to the General Assembly's questions last session, our consultants drilled more deeply into the relative economic merits of utility-ownership versus third-party ownership of new generation. And in light of renewed legislative and public interest in the possibility of full, take-back-the-plants re-regulation, we asked Kaye Scholer and Levitan to perform an economic analysis of a hypothetical condemnation and a return to rate-based regulation of the former Pepco generation assets, now owned by Mirant.

In the Interim Report, we used the term "re-regulation" broadly, *i.e.*, to encompass the range of possible Commission or legislative responses to the deregulated markets' failure to ensure reliable, cost-effective electricity for Maryland consumers. In that sense of the word, the Commission believes that the public interest compels some re-regulation of Maryland's electricity markets – or, put another way, that the public interest is not served by de-regulation that requires the Commission to wait passively for market forces to deliver a reliable supply of electricity at reasonable rates. And since issuing the Interim Report, the Commission already has "re-regulated" to some degree, in that we have directed Maryland's investor-owned utilities ("IOUs") [3] to obtain demand response resources that the market had not delivered.

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[3] Maryland's IOUs are Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("Delmarva"), Potomac Electric Power Company ("Pepco"), and The Potomac Edison Company d/b/a Allegheny Power ("Allegheny").

The question now, and the question this Report addresses, is the extent of re- regulation that best serves the public interest. Based on our consultants' updated analysis of the Maryland electricity markets and broader conditions, we offer three fundamental observations and recommendations:

1. As discussed below, the Commission has undertaken and is recommending incremental re-regulation for the purposes of ensuring a reliable supply of electricity or to obtain economic benefits for ratepayers. The Commission has the authority under current law to require Maryland's IOUs to build, own and operate plants under cost-of-service regulation or to issue competitive solicitations for new plants. In addition to the reliability measures already under way, we will initiate an investigation in the coming year to determine whether and on what terms to build additional generation for economic reasons.

   We cannot, however, recommend that the General Assembly pursue full re-regulation—the magnitude and uncertainty of the benefits, relative to the high cost of achieving the outcome do not clearly warrant the return to rate base regulation. Moreover, there are a number of other potentially serious risk factors that could create unanticipated, adverse consequences for Maryland's ratepayers. Rather than seeking to re-regulate, we recommend that the General Assembly consider legislation that would expand the range of options for obtaining new

> generation, while leaving the Commission the flexibility to respond to evolving economic and market conditions and ensure that new generation serves ratepayers' interests.

The Commission's Interim Report focused on the relative economic benefits to ratepayers from various new generation options – "re-regulation light," as it were – because we and our consultants concluded that the fair market value of the Maryland generation fleet would be too high to warrant further analysis of condemning and returning them to cost-of-service regulation. Our consultants' updated reports refresh the analyses of the "light" options to reflect current conditions and projections and, as detailed below, the results compel us to undertake a new investigation in 2009 to determine whether and on what terms to direct or solicit the construction of one or more new power plants in Maryland.

In addition, however, and in light of renewed public interest in a potential return to rate-based regulation, we also asked Levitan to analyze a hypothetical return to full regulation in one Maryland service territory. This was, by necessity, an academic exercise – the pending request for approval of Constellation Energy Group's proposed transaction with MidAmerican Energy Holdings, Inc. prevents the Commission from conducting and offering any analysis (outside of our docketed proceedings) of the value of Constellation's generation fleet, which comprises 43 percent of Maryland's in-state generation capacity resources.[4] We also

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[4] Accordingly, we offer no opinion or analysis on the question of whether or, if so, under what conditions, Constellation's generation fleet could or should be returned to BGE and brought under cost-of-service regulation. To the extent we discuss State-

framed Levitan's task in purely economic terms– both reports discuss the significant risk factors that would have to be overcome, but Levitan's analysis did not factor in the timing, likelihood of success, or potential cost associated with those risk factors.

With those caveats, Levitan's analysis reveals that condemnation of the Mirant generation assets followed by their operation under rate-based regulation could be economically beneficial to ratepayers living in the Pepco territory, even if the plants are purchased at fair market value and even if one assumes that Pepco's parent company, Pepco Holdings, Inc., incurred taxable debt to purchase them (the benefits are more favorable if the General Assembly were to form a power authority that could issue tax- advantaged financing).[5] Even if re-regulation of the former Pepco plants were desired, full State-wide re-regulation is not the best option for Maryland's energy future:

> *First*, State-wide re-regulation may have the effect of chilling merchant build-out in Maryland, thereby requiring the IOUs or the Authority to support additional generation require in this State for reliability for a significant period of time. According to Levitan's assumption, to keep the lights on in SWMAAC, the region in PJM in which central Maryland is located, requires the addition of almost 3,500 MW by 2007, a substantial amount of

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wide re-regulation, we assume only that such an outcome might hypothetically be possible for the Constellation fleet, without regard to whether or how that could be accomplished.

[5] It is important to note that the approximate value derived by Levitan was based on relatively high energy and capacity prices and did not account for the current implosion in global credit markets.

which may need to be borne by ratepayers under a State-wide re-regulation scenario.

Second, a return to rate base regulation will likely require an end to the customer choice program, as permitting customers to migrate from IOU service could have a significant negative impact on the ratepayers who remain on IOU service.

Third, ratepayers will be exposed to both earning upsides and downsides from year to year. In today's volatile markets, that exposure could be extreme, and in our opinion, much too risky to place upon the ratepayers of this State, many of whom are struggling in these uncertain times.

Fourth, re-regulating the existing generation plants in the Maryland portion of the Pepco service territory would mean re- acquiring an aging, largely coal-based fleet that will need costly maintenance, ongoing environmental upgrades if state or Federal environmental regulations tighten and could become technologically obsolete.

Fifth, the practical constraints associated with developing the infrastructure to manage and operate the generation assets will require significant time and manpower. While these functions could be outsourced, obviously the ratepayers will pay a premium for that service.

Sixth, determining the fair market value of the assets is driven largely by assumptions made with respect to energy and capacity prices within PJM—the actual value of those assets may be significantly higher or lower

depending upon the market conditions that exist on any given day.

Seventh, the transaction costs, primarily advisory costs, associated with effectuating a return of the assets to rate-base regulation may be significant. In addition, if the transaction is completed by condemnation of the assets, a protracted and expensive legal battle may result.

Eighth, assuming a return to rate-base regulation through an Authority structure, it is unclear what effect such a large debt issuance may have on the State's bond rating. Given that the size of the debt issuance required to return to rate-base regulation exceeds the outstanding indebtedness of the MTA by more than 4 times, any such issuance may negatively affect the State's bond rating. In addition, it is unclear whether the existing credit markets would have an appetite for such a large debt issuance, whether by an Authority or by the IOUs.[6]

For all of these reasons, we conclude that reacquiring these plants and having ratepayers assume the risks of owning and operating them are unlikely to be worth the potentially insurmountable expense, probable litigation and likely disruption to Maryland's electricity markets.

Our reluctance to recommend full, turn-back-the-clock re-regulation should not be read as an endorsement of the decision in 1999 to restructure Maryland's electricity markets. Our recommendation

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[6] *See* Levitan report at 5.

to look forward stems instead from our recognition, after two years of modeling and analysis, that seeking to unscramble the omelet will impose risks on Maryland ratepayers that could well not be worth the uncertain reward, particularly if nuclear energy is to play an expanded role in Maryland's energy future. [7] We recommend an emphasis on the future, *i.e.*, on augmenting and replacing existing generation with new and cleaner plants, more aggressive management of the ongoing supply mix, including investment in conservation, demand response and energy efficiency, and reasoned, ratepayer-conscious decisions about when and what to add and on what terms. In contrast, we fear that saddling ratepayers with the debt and risk from an all-or-nothing, retroactive re-regulation strategy will threaten existing projects, jeopardize our IOUs' ability to build more later, and potentially initiate years of litigation that may paralyze Maryland's electricity markets at this critical juncture.

The Commission can use its existing re-regulation authority to direct Maryland's IOUs to construct and operate new generation under cost-of-service regulation, and will consider in future proceedings whether cost of service regulation of new plants is the best option for ratepayers.[8] And because our consultants' updated economic analysis suggests that ratepayers would benefit from additional generation, we will investigate specifically whether, how and under what terms new generation would benefit ratepayers. But

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[7] We express no opinion here on the pending certificate of public convenience and necessity for Calvert Cliffs 3, but simply recognize the magnitude of the resources necessary to add new nuclear generation.

[8] Public Utility Companies Art., § 7-510(c)(6)(2008).

the constantly changing economic and market conditions lead us to doubt that a rigid commitment to a single approach to providing reliable generation capacity will be in the ratepayers' long-term interest. We recommend that the General Assembly ensure that regulated plants remain one of the options available to the Commission and Maryland's IOUs, while leaving the Commission with the authority to determine the cost-recovery mechanism that best serves the ratepayers' interests. To the extent the General Assembly wishes to consider new legislation in this regard, we recommend that any legislation serve to expand the ways in which new generation might be brought to Maryland rather than restricting them.[9]

2. With regard to *reliability*, Maryland and the Mid-Atlantic region still face a potential capacity shortfall in 2011 and thereafter, but the outlook has improved somewhat and the Commission has begun the process of directing new resources to fill the "gap."

In the Interim Report, we highlighted testimony by PJM Interconnection L.L.C. ("PJM"),[10] to the effect that Maryland faced a potential regional shortage of electricity to serve the projected demand at peak times, *i.e.*, hot summer days, beginning in 2011. We noted then that 2008 would bring two developments

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[9] For example, during the 2008 session of the General Assembly, the Commission supported House Bill 1578 as amended by the House of Delegates. HB 1578, as amended, would have authorized the Commission to allow a consortium of two or more Maryland electric companies to construct, acquire, or lease, and operate, regulated electric generating stations.

[10] PJM operates the transmission system and wholesale electricity markets that serve Maryland and adjoining states.

bearing directly on the fact and extent of a potential shortage – *first*, the January and May Reliability Pricing Model ("RPM")[11] auctions, which established the amount of capacity committed to be available through May 2012, and *second*, the hearings and decisions in adjoining states regarding the siting and construction of the Trans-Allegheny Interstate Line ("TrAIL"), a critically important multi-state transmission line project.

In early 2008, after reviewing a demand response program filed by Baltimore Gas and Electric, the Commission directed the state's major electric companies to indicate how many megawatts of cost-effective demand response programs could be developed for residential customers in time for the 2011 RPM auction. We focused on the residential demand response programs because demand response programs reduce customer's load at peak times and many commercial and industrial customers already participate in PJM demand response programs. As a result of this initial directive, the Commission approved programs in early 2008 that permitted Maryland IOUs to bid almost 500 megawatts – essentially a power plant's worth – of new demand response into the 2011 RPM auction under Commission-approved programs that were designed to be surcharge-neutral, even to non-participants.

These programs were a good start, and the landscape has improved somewhat in other ways. Although the January and May 2008 RPM auctions did not yield enough committed resources to avoid a shortfall by

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[11] The purpose and operation of RPM are explained in detail in the Interim Report, at 10-11, 17-25, and in Levitan's 2007 report, at 43-51.

themselves if TrAIL is not completed by 2011, the TrAIL project received the necessary regulatory approvals from Virginia, West Virginia and Pennsylvania, giving us greater confidence that the line will be built. That said, we do not know when TrAIL will be in service and we have no way to control or influence the regulatory or construction processes for this project, all of which occur outside of Maryland.

After reviewing the results of the May RPM auction, the Commission again took affirmative steps to obtain the additional supply Maryland needs. In July, we opened a new proceeding, the "Gap RFP" case,[12] to identify the size of the capacity "gap" in 2011-12 and to determine how best to fill it. We received and reviewed filings from more than twenty-five parties, including an updated analysis from PJM, and heard testimony over two days in October. The testimony revealed, among other things that Maryland's reliability challenges would resurface in 2013, even with TrAIL in place by 2011, if PATH is not on line as well. Some witnesses also offered reason to question whether energy from the Midwest would continue to be plentiful or relatively inexpensive indefinitely. And the Commission Staff testified that there likely are significant quantities of untapped demand response and distributed generation that could be acquired quickly and relatively inexpensively to begin filling the gap.

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[12] *In the Matter of the Investigation of the Process and Criteria for Use In Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems In the State of Maryland*, Case No. 9149.

Before directing new generation for reliability – an option that remains and that we will continue to consider – the Commission decided first, on November 6, to direct the IOUs to issue Requests for Proposals ("RFPs") for demand response, beyond what they have included in their EmPower Maryland filings, and for Commission Staff to form a distributed generation workgroup that will facilitate greater participation by distributed generation in PJM demand response programs. After seeing how much low-hanging fruit this effort will bear, and as circumstances continue to evolve – particularly as transmission line projects progress, as demand responds to changing economic conditions, and as we see the results of this year's demand response and energy efficiency efforts – we will determine whether and to what extent additional measures are necessary, including but not limited to new generation for reliability. In recognition of the regional nature of Maryland's potential reliability issues, the Commission also initiated a Regional Reliability Summit through PJM that, on November 7, brought Commissioners from affected States together to discuss the scope of the problem and potential coordinated solutions, including demand response and new generation. Our recommendation below regarding new generation for economic reasons may make the case for additional generation more compelling, but we will need to study the alternatives more thoroughly and directly before making a final decision.

There also is reason to believe that demand and consumption will begin to decline, or at least grow more slowly, in 2009. Both the IOUs and PJM have amended their load forecasts downward for 2009-11 to account for the economic downturn, and we already have begun to see some reductions in year-over-year consumption in the IOUs' monthly rate reconciliation

reports. Moreover, the Commission has completed its EmPower Maryland Act proceedings and we will, as that Act requires, approve cost- effective energy efficiency and demand response programs by year-end. Although these programs will take some time to implement, we expect that they will augment any exogenous reductions in consumption and peak demand by 2011 and lower the usage baselines as the economy recovers.

3. Maryland ratepayers would reap *economic benefits* from additional capacity in the form of new generation or demand- side resources. Accordingly, after ruling on the pending EmPower Maryland Act proposals, we will investigate in the coming year whether, when and how to build additional generation in Maryland. We also will continue our review of Standard Offer Service procurement to determine whether altering the current method could bring additional benefits.

Our consultants' updated analyses confirm that additional capacity will yield economic benefits to ratepayers, although the relative benefits of different approaches has changed somewhat from last year.

One conclusion from last year's report remains unchanged: taking and maintaining control of Maryland's energy future will require us to continue our aggressive pursuit of cost-effective demand-side management and energy efficiency resources. The key term is cost-effective – we remain concerned about the costs of implementing these programs and ensuring that the opportunities for consumers to reap real savings are distributed fairly. The potential aggregate savings in capacity and energy costs is substantial, the

economic and environmental benefits real as well, and the cost far lower than the equivalent amount of new generation. As required by the EmPower Maryland Act, we will rule by year-end on the suites of demand response and energy efficiency programs filed by Maryland's utilities. Done right, demand-side programs offer significant savings opportunities for participants and non-participants alike.

With regard to generation options, we asked Levitan for the Final Report to compare the build or lease (through power purchase agreements ("PPA")) of 1,080 MW of new, efficient combined cycle ("CC") plants in Maryland against an "overbuild" scenario, which contemplated the build-out of more than 1,080 MW of CC plants and sustained that "overhang" for a period of time. Levitan's analysis demonstrates that ratepayers will benefit from approximately 1,080 MW of CC plants– approximately two plants – and the benefits to ratepayers are roughly the same whether the unit is owned by an IOU or provided under a long-term power purchase agreement ("PPA"). The analysis of the "overbuild" scenario (building or contracting for more than the 1,080 MW beyond Levitan's Reference Case) reveals some additional value beyond the construction of the initial 1,080 MW plants, but not nearly enough incremental benefit to offset the risks and costs of the overbuild. We conclude from this analysis that building new generation in Maryland will benefit ratepayers, but only to a point, at which the cost of building additional megawatts does not justify the return.

As always, the art lies in determining whether and when to direct construction, given the rapidly shifting economic conditions and mix of pending transmission and generation projects already in progress, and how

the ownership and operation of that generation should be structured. During 2008, the Commission has reviewed applications for certificates of public convenience and necessity for the construction of plants that would add 831 MW of additional capacity in Maryland, and issued one exemption for 70 MW of wind capacity. Of course, as we learned most acutely in June in connection with a project was certificated in 2005 but never built, a certificate is only one of many steps, and we are continually monitoring existing projects to determine whether, when, and under what circumstances they might come to fruition.

The year between the issuance of the Interim Report and the Final Report has been a time of unprecedented economic volatility. Among other things, we have seen fuel prices spike and retreat in 2008, the cost of building materials peak then plummet, and credit markets tighten, and in some cases, shut down altogether. These wild swings in economic conditions leave us unable to say with any confidence that Maryland ratepayers categorically will be better in the long-term under one or another mode of generation ownership. At the moment, recouping the cost of building generation under cost-of-service regulation[13] could provide slightly greater economic benefit to ratepayers, but we cannot say that this will always be the case. From a policy perspective, then, we believe that Maryland ratepayers will benefit if merchant generators can build here, so long as the Commission simultaneously retains the authority to direct the construction of utility-owned generation if they don't. We will, of course, continue to monitor the wholesale

[13] The generation could be built by an IOU or by a third party under an RFP process through which the third party is compensated under cost-of-service regulation.

prices of electricity, the status of pending generation and transmission projects, and other factors to determine when best to direct the construction of resources the markets are failing to deliver.

In light of continuing legislative and public interest in renewables, we also asked Levitan to update its analysis of the wind cases and, unlike last year, the firm performed a separate economic analysis of incremental solar generation. In developing the off-shore wind case, Levitan used the actual terms of the BlueWater Wind contract with Delmarva in Delaware, plus updated (and more favorable) operational data, in projecting the performance of the farm. The resulting analysis is more precise than last year's, but the ultimate conclusion is essentially the same: although on-shore wind generation does provide some economic benefit above and beyond its environmental benefit, the costs of off-shore wind far exceed the benefits except under a "peak oil scenario" that assumes especially high fuel prices. Moreover, under current economic and technological conditions, solar energy does not sustain value to ratepayers in light of the decline in the price of renewable energy credits ("RECs") and the assumption that the 30% Federal investment tax credit ends in 2017.

II. ABBREVIATED LEGISLATIVE HISTORY AND SELECTED PROCEEDINGS SINCE THE INTERIM REPORT

In Part I of its Interim Report, the PSC provided a detailed history of the events preceding S.B. 400,

which we will not repeat here.[14] S.B. 400 required the PSC to:

> conduct hearings, including the use of any necessary outside experts and consultants, to study and evaluate the status of electric restructuring in the State as it pertains to the current and future availability of competitive generation to residential and small commercial customers and the structure, procurement, and terms and conditions of standard offer service for residential and small commercial customers.
>
> In its evaluation, the Commission shall consider changes that are necessary to provide residential and small business customers the benefit of a reliable electric system at the best possible price, including options for re-regulation, if advisable, and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility.
>
> In its evaluation, the Commission shall also consider the availability of adequate transmission and generation facilities to serve the electrical load demands of all customers in the State, pricing and physical constraints on the electrical transmission and distribution grids in the State, and options and policy recommendations to provide an adequate, safe and reliable supply of electricity at a reasonable cost to all customers in the State.[15]

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[14] Interim Report, Part I, at 5-7.

[15] S.B. 400, § 7(a)(1)-(3).

In conducting the analysis described above, the General Assembly specifically directed the PSC to consider the implications of certain approaches:

- Requiring or allowing investor-owned electric companies to purchase electricity by competitive or negotiated contracts of various durations or through other appropriate methods to minimize price volatility;
- Requiring or allowing investor-owned electric companies to construct, acquire, or lease peak load or other generating plants and associated transmission lines;
- Providing a process, at the time bids by investor owned electric companies for electricity supply are obtained for the standard offer service, to solicit bids for the procurement of cost-effective energy efficiency and conservation programs and services if energy efficiency and conservation programs are less expensive than electricity generation;
- Establishing a long-term goal for savings over a period of time of the total residential retail energy consumed in a year in an electric company's service territory through the procurement and implementation of cost effective energy efficiency and conservation programs and services;
- Providing a process to allow investor-owned electric companies to obtain a portion of their electricity supply for standard offer service through the negotiation of bilateral contracts with wholesale electricity suppliers, either in conjunction with or outside of

procurement through competitive wholesale auctions;

- Allowing opt-out aggregation of residential electric customer demand and small commercial electric customer demand by local governments in the service territories of investor-owned electric companies;[16]
- Establishing an office of retail market development; and
- Requiring investor-owned electric companies to purchase accounts receivable of electricity suppliers for residential and small commercial accounts.[17]

In Part I of its Interim Report, the PSC reported on proceedings held in compliance with S.B. 400 during calendar year 2007.[18] Since the last report, the PSC has overseen additional proceedings aimed at resolving the important issues highlighted by S.B. 400, beginning with the potential electricity shortage:

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[16] In the Order Initiating Proceeding, *in the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Order No. 81563, Case No. 9117 (Aug. 16, 2007), the PSC ordered the parties to consider whether there were price benefits for aggregating low-income residential customers. Evaluation of the submissions in Case 9117 is ongoing, with comment deadlines of November 21 and December 5, and hearings set for December 18 and 19, and we will report further to the General Assembly on aggregation once we have reached a decision.

[17] *See* Rulemaking 17 (notice of final rule to be published in Maryland Register December 19, 2008).

[18] Interim Report, Part I, at 8-10.

- *The "Gap RFP" Case*. As set forth in greater detail below,[19] the Commission opened a proceeding, Case No. 9149, for the purpose of defining and investigating how to fill the potential capacity shortfall in 2011-12 and thereafter. The Commission also asked PJM to convene a Regional Reliability Summit, which was held on November 7, 2008 and involved discussions among representatives from PJM and fellow PJM states.

- *Standard Offer Service Procurement*. During 2008, the PSC ordered additional investigation in Case No. 9117, In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service[SOS] for Residential and Small Commercial Customers in Maryland. We ordered the IOUs to evaluate long-term procurement plans for providing SOS to residential and small commercial customers, with resource mixes that include new generation, generation upgrades, demand response programs, PSC-approved residential energy efficiency programs, potential or proposed commercial and industrial energy efficiency programs, implementation of a smart grid system and upgrades to the transmission and distribution system, and to recommend which portfolio mix best balances the "competing mandates set forth in Senate Bill 400, that is, 'a portfolio

[19] See subsection IV.B below, at 20.

of electricity supply that provides electricity at the lowest cost with the least volatility.'"[20] The IOUs submitted their evaluations and recommendations by October 1, 2008, and the PSC stated in its order that it would afford the parties the opportunity to comment and to "hold further proceedings." Parties filed comments on the IOUs' plans by November 21, and the IOUs have until December 5 to file reply comments. Hearings are scheduled for December 15, 17 and 19, 2008.

- *Energy Efficiency and Demand Response – The EmPower Maryland Act Cases.* As directed by the EmPower Maryland Act, the PSC is reviewing energy efficiency and demand response proposals from five IOUs, and has held more than five days of hearings on the filings submitted. Cases No. 9153 through 9157, In the Matter of Allegheny Power's, Baltimore Gas & Electric Company's, Potomac Electric Power Company's, Delmarva Power & Light's, and SMECO's [respectively] Energy Efficiency, Conservation, and Demand Response Program Pursuant to the EmPower Maryland Energy Efficiency Act of 2008. The last EmPower Maryland hearing was held on December 9, 2008, and on December 1 the PSC issued an interim order directing the parties to draft an RFP for a baseline study against which future progress may be measured. The

[20] S.B. 400, § 7(a)(1)-(2).

PSC expects to issue orders on all five IOUs' proposals by December 31, 2008.

- *Retail Choice Regulations*. The PSC has held three rulemakings relevant to retail choice: Rulemaking 34, which seeks to create a uniform statewide definition of "small commercial customer," and Rulemakings 17 (electric) and 35 (gas), which establish regulations to protect consumers dealing with competitive electricity and gas suppliers and facilitate competitive suppliers' participation in the Maryland marketplace. In addition to setting consumer protection rules, Rulemakings 17 and 35 will, if adopted in the current form, require the IOUs to purchase accounts receivable of electricity suppliers for residential and small commercial customers. These proposed final rules are expected to be published in the Maryland Register on December 19.[21] These important ground rules should be firmly in place by early 2009.

III. STATUS OF ELECTRIC RESTRUCTURING

Part II of the Interim Report, filed on January 17, 2008, detailed the history and status of numerous long-lingering disputes regarding the mechanics of electric restructuring in Maryland, most notably of the former BGE generation fleet. Those disputes have

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[21] The PSC also completed rulemakings on small system interconnection (RM 31), solar energy (RM 32) and energy-efficient distribution transformers (RM 33). Rulemaking 34 is still pending.

since been resolved in a settlement that was memorialized in Senate Bill 1013 of 2008 and is summarized below. We also offer brief updates on the status of retail electric choice and Standard Offer Service procurement, the latter of which is currently under a detailed review.

A. Constellation Energy Group Settlement of Post-Deregulation Matters

In March 2008, the Governor, General Assembly and the PSC reached a settlement with Constellation Energy Group that resolved all claims arising out of the 1999 deregulation. The settlement's total benefit to ratepayers is estimated to be $2.033 billion. As part of the settlement, BGE's residential customers received a one-time refund of $170 per household as a credit on their bill in September of 2008, equaling $187 million in rate relief. The settlement also eliminated a $5.2 billion BGE ratepayer liability for decommissioning Calvert Cliffs Nuclear Power Plants, saving ratepayers $1.5 billion in future contributions. All responsibility for proper funding and oversight of the funding for the nuclear decommissioning of the Calvert Cliffs facility going forward is to be borne by Constellation.[22] Constellation also agreed, all else being equal, to make Calvert Cliffs 3 its number one site priority if it moved forward with plans for a new nuclear plant. And the settlement resolved all pending claims or lawsuits arising out of the 1999 Settlement Agreement, including the restoration of

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[22] Because the terms of SB 1 were left intact, all ratepayers will continue to pay decommissioning charges through 2016, but residential ratepayers will continue to be credited $18.6 million annually through 2016. After that date, the credit ends, and there will be no further collections or credits.

$346 million out of $386 million in credits enacted in Senate Bill 1 in 2006.

The settlement included amendments to the Public Utility Companies Article that permit up to 20 percent of Constellation stock to be acquired without advance approval of the PSC, and remove the "class restrictions" that currently limit what types of companies can buy Constellation stock. The PSC retains approval authority when a purchaser exercises "substantial influence" over BGE or other public service companies, even if it has not purchased 20 percent of the holding company's stock. The legislation also incorporated into Maryland law certain authority that the Commission has under federal law to obtain relevant documents from non-regulated affiliates of regulated utilities by subpoena.

Finally, BGE agreed to delay any changes in distribution rates until October 2009, and to be limited to a 5 percent increase unless the PSC determined that a higher rate would be in the public interest, and not to file any follow-up rate case until August 2010. The legislation entitled BGE to utilize a certain depreciation method until its next rate case. BGE also agreed to add at least two independent directors to its Board, which sits separately from Constellation's, and ultimately added three in mid-2008.

B. Status of Retail Electric Supply

The Electric Customer Choice and Competition Act of 1999 restructured the electricity industry in Maryland. Among other things, the Maryland General Assembly determined that the supply of electricity would be partially restructured and that customers

could choose their electricity provider from a list of qualified suppliers.[23]

Each of Maryland's IOUs offers an electricity supply service known as Standard Offer Service ("SOS"). If a retail customer is unable to or does not choose to purchase electricity from a competitive supplier, the local electric company provides his or her supply under SOS.[24] At the onset of restructuring, SOS service included a rate reduction and an extended cap on the SOS price to provide an immediate benefit for the various customer classes that decided not to shop. It was envisioned that the regulated distribution companies would obtain and provide SOS power supplies for a set number of years to afford the competitive retail markets time to mature. However, during the transition period, the wholesale market price of electricity rose and a competitive market for retail electricity supply did not develop as expected.[25] Competitive suppliers have not been able to consistently make offers below the SOS rates for the residential and small commercial customer classes.

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[23] Electricity suppliers operating in Maryland must first obtain a license and abide by applicable standards (e.g., financial integrity, accurate consumer information) before PSC issues a license to operate in the State. Qualified suppliers either own electric generation facilities or purchase the output of generation facilities operating in the PJM wholesale market.

[24] Fixed rates and SOS provisions were established for IOU customers. Customers of Maryland's two electric cooperatives, SMECO and Choptank Electric, were given the ability to select their own electricity suppliers.

[25] The rise in retail electricity prices is in part a reflection of a rise in underlying fossil-fuel prices, particularly natural gas, as well as constraints on the electric transmission system that limits the import of lower cost electricity into Maryland.

The total statewide number of distribution service accounts eligible for electric choice, as of September 2008, was 2,202,890 of which 1,970,647 were residential and 232,243 were non-residential. The Commission's most recent choice enrollment report indicates that the electric suppliers have made significant inroads in providing electricity supplies to the commercial and industrial businesses that operate in Maryland; particularly, the large commercial and industrial classes. As table III.B.1 indicates, competitive electric suppliers supply electricity to the bulk of the large commercial and industrial ("C&I") accounts (87.5 percent), nearly half the mid-sized accounts (44.7 percent), but only a minor share of the small C&I accounts (15.9 percent). Moreover, few residential customers have chosen electric supply via competitive electric suppliers.

Table III.B.1 Percentage of Customers Served by Electric Suppliers

Distribution	Reside	Small C & I	Mid C & I	Large C & I	Total
Allegheny Power	0.0%	14.8%	38.0%	80.0%	2.4%
Baltimore Gas and	2.6%	14.6%	45.9%	91.1%	4.5%
Delmarva Power &	0.8%	12.6%	39.7%	92.5%	3.3%
Potomac Electric	5.9%	23.0%	46.8%	84.3%	8.3%
Total	**3.0%**	**15.9**	**44.7**	**87.5**	**5.1%**

Note: C&I indicates Commercial and Industrial Accounts

Source: Maryland Public Service Commission, Electric Choice Enrollment Monthly Report All Investors Owned Utilities in Maryland Month Ending September 2008

The Commission continues to oversee the SOS procurement process. This process provides default service for residential and small- and medium-sized commercial customers. For the residential and small- and medium-sized commercial customers, SOS service is procured through wholesale market contracts. Large industrial SOS customers pay a variable hourly rate. The Maryland IOUs do not own or control generation supply resources (with some possible minor exceptions), but electricity for SOS from qualified suppliers that are not price-regulated. As a result, retail procurements of electricity from either SOS or directly from qualified suppliers are largely dependent on underlying wholesale market conditions.

To mitigate retail price volatility, the Commission oversees SOS procurements of electricity supply for the residential and small commercial customers. This load is filled through two-year laddered contracts, with 25 percent of the load procured twice per year. SOS electricity supply for Type II customers is procured using three-month contracts, with 100 percent of the load procured four times per year.

As part of Senate Bill 400,[26] § 7-510 of the Public Utility Companies Article required the Commission to establish a wholesale power procurement process that is "designed to obtain the best prices for residential and small commercial customers in light of prevailing market conditions at the time of the procurement and the need to protect these customers against excessive price increases."[27] On August 16, 2007, the Commission opened a new proceeding to evaluate and consider alternatives to the auction methodology, including the

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[26] Chapter 549 of 2007.

[27] PUC Article Section 7-510(c)(4)(ii).

actively managed portfolio approach of SMECO to the Request for Proposal process for full requirements service used by the IOUs and aggregation for low-income customers.[28] The Commission later expanded the case to consider procedures to solicit bids for cost-effective energy efficiency and conservation programs and services and the possibility of directing electric companies to build, acquire or lease peak-load or other generating plants.

After testimony and hearings for both phases, the Commission issued an order on January 3, 2008, directing the IOUs to submit proposed diversified SOS procurement plans. The utilities were instructed to utilize contracts of between ten and fifteen years in length, based on identified parameters and to mix those longer-term contracts with other products. The utilities filed their plans on October 1, 2008, various parties commented on them, and the Commission will conduct hearings on December 15, 17 and 19, 2008. A further order should issue during the first part of 2009.

IV. THE STATE OF ELECTRICITY IN MARYLAND AND RECOMMENDATIONS FOR "RE-REGULATION"

A. Committed Capacity And Transmission Capabilities Still Fall Short Of Maryland's Peak Needs Beginning In 2011-12.

Maryland's electric system is part of an integrated transmission system that is coordinated on the

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[28] In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland, Case No. 9117.

wholesale level by PJM. PJM dispatches generation located within its regional boundaries (the "RTO"),[29] and coordinates the transmission of that electricity into and within the State of Maryland. IOUs are responsible for maintaining the transmission and distribution lines that deliver electricity to individual homes.

In order to coordinate energy transmission, PJM dispatches generation located within the RTO in a manner that balances the supply and demand of electricity within the RTO. As a means of ensuring reliability of the electric system in the RTO, PJM annually conducts a long-term planning process that compares the potential available generation located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO and establishes the amount of generation and transmission required to maintain the reliability of the electric grid within PJM. This process produces the Regional Transmission Expansion Plan. Using this information, PJM evaluates bids from generators and other resources three years in advance to be available for a one year delivery period (up to three years for new generation) through the Reliability Planning Model ("RPM") Base Residual Auction ("BRA").

Once PJM completes its Regional Transmission Expansion Plan and conducts its Reliability Planning Model Auction, PJM is in a position to evaluate the

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[29] The RTO includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

reliability of its system. PJM must operate the transmission system to meet reliability criteria established by the Federal Energy Regulatory Commission and administered by the North America Electric Reliability Corporation ("NERC").

1. *The 2011/2012 Capacity Auctions*

In May 2008, PJM held its first BRA for the 2011/2012 delivery period.[30] The PJM planning process for the 2011/2012 delivery period made the questionable assumption that the TrAIL line would be in service on or before June 1, 2011, even though construction has not yet commenced.[31] As a result, the 2011/2012 BRA procured the amount of capacity required by PJM under that assumption rather than the amount required without it. In addition, according to PJM, approximately 3,000 MWs of planned or existing generation assets located within the region were not "accepted" by PJM through the 2011/2012 BRA and therefore are uncommitted to PJM for the 2011/2012 delivery year through the BRA process (the "2011/2012 Uncommitted Resources").[32] PJM has testified that not all of 2011/2012 Uncommitted Resources can reliably be counted on to deliver energy during the 2011/2012 delivery period either because the generation owner will not perform the requisite maintenance on the units or because planned generation may not be completed before the delivery year commences.[33] But PJM agrees that its do not authorize

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[30] The delivery year runs from June 1, 2011 to May 31, 2012.

[31] See pages 16-17 for details.

[32] Administrative Meeting-May 21, 2008; PJM Status Reports presented by Michael J. Kormos; *see also* Transcript of Hearing, Oct. 3, 2008 (M. Kormos) at 36.

[33] Transcript of Hearing, Oct. 3, 2008 (M. Kormos), at 34-35

it to hold incremental capacity auctions to obtain commitments from the 2011/2012 Uncommitted Resources unless the need for additional capacity if the need arises from a delay to the in service date of the TrAIL line.[34]

Accordingly, at this point, any process for obtaining commitments from the 2011/2012 Uncommitted Resources, or any other resources for that time period, falls to this Commission – hence the Gap RFP case and the other "re-regulation" steps that the Commission has taken to secure additional capacity. Although PJM and its stakeholders are currently evaluating changes in PJM's tariff that might, after approval by FERC, authorize PJM to conduct incremental auction for reasons other than increasing load forecasts, the timing and outcome of that stakeholder process is unpredictable, and we cannot leave the integrity of Maryland's electricity supply to these processes.[35]

2. *Critical Backbone Transmission Line Projects Have Progressed Since The Interim Report, But Remain Uncertain.*

In the Interim Report, the Commission identified and discussed two critical transmission line projects: The Trans-Allegheny Interstate Line ("TrAIL") TrAIL and Potomac-Appalachian Transmission Highline project ("PATH"). The first of these projects, TrAIL, has surmounted important regulatory hurdles in other states, while PATH and another regional line, MAPP, appear to be making progress toward filings and construction. But although the Commission will play a role in siting and possibly approving the Maryland

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[34] *Id.* at 77-79, 83-85, 105-06.

[35] *Id.*

portions of PATH and MAPP, the Commission does not and cannot direct the timing or in-service dates of these projects, leaving uncertainty regarding the role these lines can or will play in addressing Maryland's reliability issues.

Trans-Allegheny Interstate Line

TrAIL is an alternating current single circuit 500 kV overhead transmission line that begins in Washington County, Pennsylvania, passes through West Virginia, and ends in Loudon County, Virginia. According to PJM, TrAIL provides critical support to the eastern Mid-Atlantic PJM area and maintains reliability in Northern Virginia and the Baltimore/Washington D.C. area once comes on line in June 2011. The expectation is that this line will import electricity from low-cost baseload generators in the Midwest to Maryland.

TrAIL has been approved by the West Virginia (August 1, 2008), Virginia (October 7, 2008), and Pennsylvania (November 13, 2008) Commissions. The West Virginia approval remains subject to certain conditions that the company believes will be resolved now that the other states have approved. Pennsylvania's recent approval removes a significant hurdle.

The project's rate of return also has been resolved. On July 21, 2008, the Federal Energy Regulatory Commission ("FERC") approved an uncontested settlement among TrAILCo, the PSC and other parties that resolved all issues relating to the transmission cost of service formula rate that governs construction and operation of the project. The PSC had contested certain incentives sought by TrAILCo that imposed an unwarranted burden that would ultimately be borne by ratepayers. As a result of the PSC's advocacy with other states, the incentive return on equity ("ROE") was reduced by settlement to 12.7 percent from 13.9 percent.[36] TrAILCo will provide a public update on the status of TrAIL to the Commission at an Administrative Meeting in January.

Potomac-Appalachian Transmission Highline (PATH)

PATH is a 765 kV transmission project that will run from Amos, West Virginia to Kemptown, Maryland. According to PJM, PATH resolves numerous overloads in the Baltimore-Washington region, beginning as early as 2013 and extending beyond 2022. PJM states that PATH will reduce the flow on existing PJM 500 kV west to east transmission paths and provide significant benefits to the constrained Baltimore/

[36] FERC docket number ER07-562

Washington area. The line as proposed by AEP is estimated to cost $1.8 billion; the return on equity proceedings are well under way at FERC, and the Commission has fought incentives that are, in our view, excessive.[37]

PATH is farther from completion than TrAIL – as recently October 17, 2008, the route of the line was reconfigured, and the final line route and other details are still being completed. We understand that PATH expects to file applications for approval by state regulatory commissions during the first quarter 2009, and the projected in-service date was recently delayed from June 2012 to June 2013.

Mid-Atlantic Power Pathway (MAPP)

As proposed, the PHI MAPP 500 kV circuit will run from Possum Point, Virginia to the Salem 500 kV station in New Jersey. The 230-mile long line is expected to be built primarily along existing right-of-ways and is intended to pass through Burches Hill, Chalk Point, Calvert Cliffs, Vienna, Indian River and Cedar Creek stations. The planned line consists primarily of overhead construction, but also includes a

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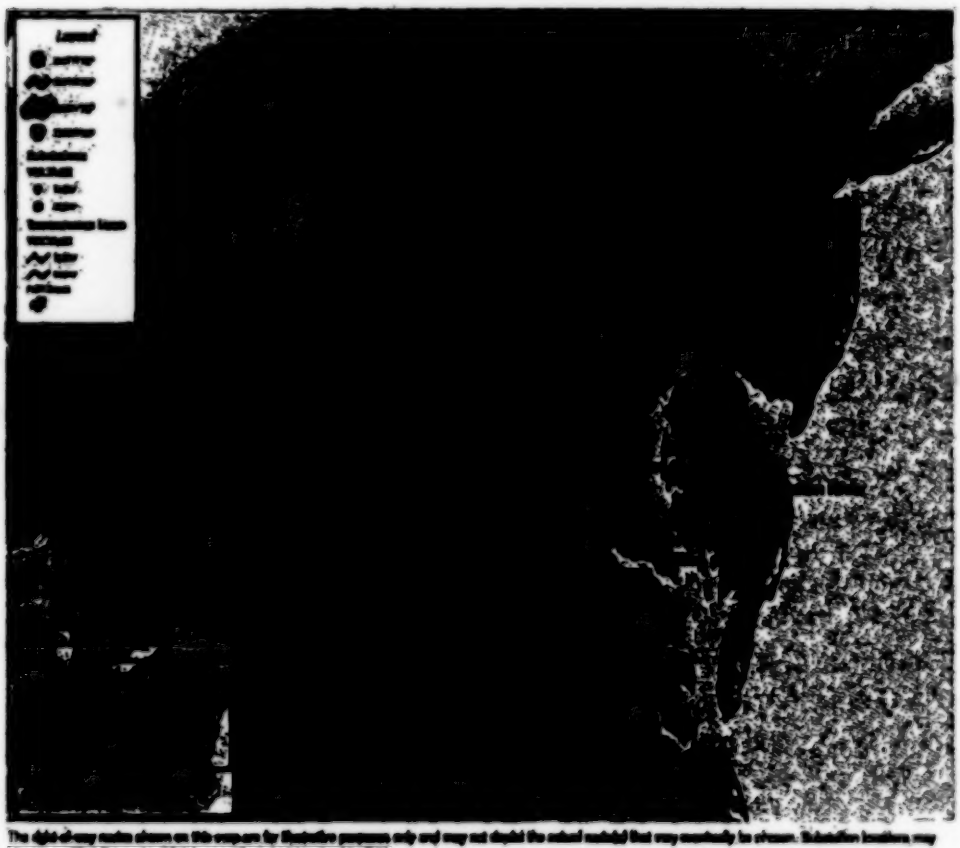
[37] On February 28, 2008, over the objections of the PSC and other parties to the amounts and multiple guarantees awarded, the FERC granted four rate incentives for the project including (1) an incentive return on equity for new transmission of 14.3 percent, (2) recovery of a return on 100 percent of prudently incurred transmission-related Construction Work in Progress prior to the project's in-service date, (3) recovery of all startup business and administrative costs incurred prior to the time that rates go into effect, and (4) authorization to recover all prudently incurred development and construction costs if the PATH project is abandoned as a result of factors beyond the control of PATH or its parents. FERC's docket number for this project is ER08-386. Motions for rehearing by the PSC and others are pending.

submarine crossing of the Chesapeake Bay. The line is estimated to cost $1.05 billion, as proposed.[38]



PJM reports that MAPP is projected to resolve 33 overloads on several interfaces in the Mid-Atlantic region, bringing congestion relief and reliability benefits to the Baltimore-Washington area and Eastern Shore, and will provide a strong path for generation into the southern part of the Delmarva peninsula. Pepco states the project will provide access to more than 1,300

[38] On November 3, 2008, in Docket No. ER08-1423, FERC authorized a 1.5 percent return on equity (ROE) adder to the company's existing 11.3 percent ROE. That will result in an overall ROE of 12.8 percent. FERC also authorized full recovery of construction work in progress and prudently incurred abandoned plant costs. The rates took effect November 1, 2008

megawatts of renewable wind generation in the western portion of PJM and will be operated using "smart grid" technology. According to FERC, the project is expected to save $113 million annually to the Mid-Atlantic region, and $70 million annually for the entire PJM region if operated as an AC line. If the portion of the project crossing under the Chesapeake Bay is built as a 640 kV high voltage direct current ("DC") line, the annual savings would be $174 million and $91 million, respectively, and reduce production costs by $58 million annually for the entire PJM region.

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To summarize:

(1) TrAIL has resolved some of the regulatory hurdles it faced, but still has not even begun construction;

(2) PATH is continuing to evolve, but its proponents have pushed back their initial deadlines for seeking regulatory approvals, and it is far from certain that either of these projects will be in-service in time to solve Maryland's (or PJM's) reliability problems; and

(3) MAPP, while helpful to the Delmarva Peninsula, New Jersey and beyond, is not expected to significantly lessen central Maryland's capacity gap.

B. Proceedings To Identify And Fill The Reliability Gap Began This Year And Are Well Under Way.

During the Commission's Summer 2007 Electricity Planning Conference,[39] PJM first reported to the Commission the possibility of electricity shortfalls on hot summer days beginning in 2011. Since then, PJM has updated its projections at least three more times—in the fall of 2007,[40] again in May 2008[41] and again in November 2008.[42] In each such report, PJM's fundamental message was the same: with the results of the 2011/2012 BRA in hand, unless TrAIL is in service by June 1, 2011, and assuming that PJM cannot rely on any capacity resources that were offered into, but not "accepted" by PJM in the 2011/2012 BRA, it appears that the Mid-Atlantic region faces a shortfall of capacity on the order of 2,600-3,000 MWs. [43] Maryland's proportionate share of the shortfall is approximately 600-690 MWs.[44]

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[39] *In the Matter Of The Commission's Maryland Electricity Planning Conference*, Public Conference No. PC9.

[40] *See* Case No. 9117, Phase II, direct Testimony of Michael J. Kormos, Senior Vice President of Reliability Services for PJM, October 19, 2007 and Reply Testimony, October 30, 2007.

[41] Administrative Meeting-May 21, 2008; PJM Status Reports presented by Michael J. Kormos.

[42] Eastern PJM Region Reliability Summit Regional Planning, November 7, 2008.

[43] It is worth noting that the RTO as a whole does not have a capacity shortfall, but rather, absent TrAIL, the transmission grid within the RTO is not strong enough to support the transmission of capacity from the generation sources to the load pockets that require it. Transcript of Hearing, Oct. 3, 2008 (M. Kormos) at

[44] *Id.*

Although, as discussed above, the outlook has improved for TrAIL to be online by 2011, PJM has testified that the relief from TrAIL could be short-lived, and another regional capacity shortfall may reappear in 2013 unless PATH is in service by then as well.[45] The PATH joint venture has recently announced that the anticipated in service date of the PATH line is now projected to be June 2013 (instead of June 2012, as previously expected), based not upon construction delays, but on "reliability studies by PJM."[46] Again, as of the date of this report, PATH has not yet begun the process of seeking regulatory approvals from the States it crosses and now will delay its filings until the first quarter of 2009.[47]

a. Case No. 9149

In response to the potential regional capacity shortfall highlighted by PJM, the Commission instituted a new proceeding in July 2008 to investigate whether and how to fill the "gap," *i.e.*, the potential regional capacity shortfall.[48] The Commission directed parties to file information regarding the extent of the potential shortfall and possible solutions. The Commission held a hearing on the matter on October 3,

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[45] *See* Transcript of Hearing, Oct. 3, 2008 (M. Kormos), at 17-18.

[46] Press Release, "PATH Announces Change to Transmission Line In-Service Date," Oct. 31, 2008.

[47] *Id.*

[48] *In the Matter of the Investigation of The Process and Criteria For Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149.

2008. PJM presented a similar analysis to that provided at the May 23, 2008 Reliability Conference and interested parties also proposed potential solutions. The hearing focused largely on how and whether Maryland can attempt to "solve" a regional capacity shortfall that affects several other states and the types of resources that can most cost-effectively be utilized to reduce the regional capacity shortfall.

On November 6, 2008, in the Commission issued an order directing the IOUs to develop and issue Requests for Proposals ("RFPs") to procure demand response and interruptible load for reliability resources above and beyond what was promised in early 2008[49] and what was proposed in the IOUs' pending EmPower Maryland Act filings, which are currently under review.[50] The IOUs were directed to submit proposed RFPs to Commission Staff by December 1, 2008.[51] Commission Staff will then make a recommendation to the Commission with respect to those RFPs on or before December 31, 2008. In addition, the Commission directed Staff to convene a distributed generation work group of all interested stakeholders, including the Maryland Department of the Environment and Maryland Energy Administration, to determine the scope of potentially available distributed generation

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[49] See subsection IV.C. below at 22-25.

[50] *In the Matter of the Investigation of the Process and Criteria For Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term reliability Problems in the State of Maryland*, Case No. 9149 at 7

[51] *Id.*

resources and propose a methodology to harness those resources.[52]

The demand response RFP Order represents an important first step designed to corral readily available and less expensive resources before deciding whether to order new construction. Once the Commission has had an opportunity to see the results of the RFP, and to consider them in the context of evolving load growth forecasts (which are declining), we will decide whether other resources, including new generation, are necessary for reliability purposes and, if so, how and under what conditions to obtain them.

b. Regional Reliability Summit

The interconnected nature of the electricity system means that any capacity shortfall affects connected regions, not just states or cities. As a result, any step taken by the Maryland Commission alone that imposes additional costs on Maryland ratepayers will require our ratepayers to bear a disproportionate share of what should be a regional burden. Accordingly, at the Commission's request, PJM convened a Regional Reliability Summit on November 7, 2008, and representatives from Maryland, New Jersey, Delaware, Virginia, the District of Columbia, Pennsylvania and Indiana participated.

The Summit featured a presentation by PJM describing the potential extent of a regional capacity shortfall if the TrAIL line is not in service by June 1, 2011.[53] PJM reiterated that its tariff, as currently approved by FERC, does not permit it to hold

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[52] *Id.* at 8.

[53] Eastern PJM Region Reliability Summit Regional Planning, November 7, 2008.

incremental auctions for the purpose of obtaining additional capacity in the event a transmission project is delayed beyond its original in-service date. As a result, PJM concluded that any regional solution, given the authority currently conferred upon PJM by its tariff, will need to be implemented by or through the affected states. Each of the states present at the Summit agreed to continue the dialogue with respect to possible solutions, long- and short-term, possibly through the Organization of PJM States, Inc. ("OPSI"). Chairman Nazarian of the PSC will assume the OPSI Presidency in 2009.

C. The Commission Began Demand-Side Management And Energy Conservation Programs Before EmPower Maryland Act.[54]

As discussed briefly in the Interim Report,[55] the PSC "substantially expanded its analysis of demand-side management and energy efficiency programs" even before the passage of the EmPower Maryland Energy

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[54] In addition to the discussion in this section, the PSC has pushed for favorable treatment of demand-side management and energy efficiency in PJM's capacity markets (*see* Section IV.E) and ordered an RFP for additional demand-side management in Case 9149 (*see* Section IV.B). While the PSC asked the IOUs to consider whether energy efficiency could be bid as part of SOS (Notice Initiating Phase II Proceeding, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers*, Case No. 9117(September 25, 2007), none proposed a means to do so at the state level. However, once energy efficiency is bid into PJM's markets it will effectively become part of Maryland SOS prices. Proposals for bidding energy efficiency into RPM are currently being considered in the PJM stakeholder process.

[55] Interim Report, Part I, at 9.

Efficiency Act of 2008 (the "EmPower Act").[56] The PSC established a collaborative process involving several IOUs, its technical staff, People's Counsel and other interested agencies, suppliers, public interest groups and consumer organizations, to consider technical standards for and operational capabilities of advanced meters, offering demand-side management programs on a competitively-neutral basis, recovery of costs of demand-side management programs, and measuring the cost-effectiveness of demand-side management programs.[57] In September 2007, after participants in the collaborative process had filed a report and comments, the PSC ordered all electric companies to develop and file energy efficiency, conservation and demand reduction plans designed to collectively achieve 50 percent of the EmPower Maryland goal.[58] The PSC also ruled on minimum technical requirements for advanced metering initiatives and the methods by which IOUs could recover demand-side management expenses and provided guidance on how it would evaluate the cost- effectiveness of demand-side management programs.

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[56] *In The Matter Of The Commission's Investigation Of Advanced Metering Technical Standards Demand Side Management Cost Effectiveness Tests, Demand Side Management Competitive Neutrality, And Recovery Of Costs Of Advanced Meters And Demand Side Management Programs.*

[57] Order No. 81448 (June 8, 2007). By a separate letter order the PSC had also established a collaborative on demand-side management and advanced metering initiatives for Pepco and Delmarva Power and Light, and it had earlier approved pilot advanced metering and demand-side management programs for BGE. *Id.* at 4. A few months later it also approved Residential Compact Fluorescent Light Programs for Pepco and Delmarva Power and Light. Order No. 81618 (September 19, 2007).

[58] Order No. 81637, Case No. 9111 (September 28, 2007).

The greatest success from the pre-EmPower Act period came from a BGE program, now called Peak Rewards. Peak Rewards is a voluntary program in which customers can agree, in exchange for bill credits, to allow BGE to install a device through which BGE can turn down the customer's air conditioning on peak demand days. As approved, Peak Rewards is surcharge-neutral, even to non-participants, because BGE can fund it with the proceeds from bidding the resulting demand response into the RPM capacity auctions. As a result of Peak Rewards, BGE bid 495 MW of demand response into the May 2008 auction – effectively a power plant's worth of demand response that substitutes for an equivalent amount of new generation. Having approved Peak Rewards, the Commission directed Pepco, Delmarva, Allegheny and SMECO on January 3, 2008 to file similar demand response programs and, with the exception of Allegheny, all of them now have programs of their own.

The energy efficiency programs filed before the EmPower Act were generally less successful. Although the Commission approved "fast-track," pilot-scale programs for most of the utilities, we rejected a broader suite of programs filed by BGE on August 18, 2008, after finding that most were not cost-effective.[59] The other utilities' filings are being considered simultaneously with the EmPower Act programs.

D. The EmPower Maryland Act Cases Accelerated The Commission's Work On Energy Efficiency And Demand Response.

During the 2008 legislative session, the General Assembly passed the EmPower Act, which recognized

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[59] *See* Letter to W Harbaugh, Aug. 18, 2008.

that energy efficiency is among the least expensive ways to meet the growing electricity demands of the State. The Act sets significant and aggressive goals for reducing the state's peak demand and energy consumption in a set time frame, *i.e.*, a 15 percent reduction in per capita electricity consumption by the end of 2015, and a 15 percent reduction in per capita peak demand by the end of 2015. The Act requires the IOUs to offer appropriate and cost-efficient programs to its residential, commercial and industrial customers designed to achieve a 5 percent reduction by 2011 and a 15 percent reduction by 2015 in per capita peak demand and a 5 percent reduction by 2011 and a 10 percent reduction by 2015 in per capital electricity consumed. Additionally, the Act requires the IOUs to include energy efficiency and conservation programs specifically targeted to low-income and low-to-moderate income communities.

The Act directed the IOUs, as well as the Southern Maryland Electric Cooperative, to submit plans to the PSC on or before September 1, 2008 that detail the companies' proposals for achieving the reduction targets. Prior to the submission date, the PSC's Technical Staff, along with the Maryland Energy Administration ("MEA"), conducted several work-group meetings with the IOUs. As a result of these meetings, the PSC issued its "EmPower Maryland Plan Outline," which provided guidance to the IOUs on how to organize, present and document their proposed EmPower Maryland Plans.

Each of the five IOUs submitted detailed plans on or before September 1, 2008. Although each proposal reflects that utility's unique customer base and prior experience with energy efficiency and conservation programs, there are numerous similarities among the

IOUs. For example, each utility's portfolio of program offerings includes appliance rebates and total home energy audits for residential customers and lighting programs and custom applications for the industrial customers. All programs include a customer education and outreach component.

The Act compels participation of MEA in the formulation and implementation of the EmPower Maryland programs. Prior to July 1, 2008, the Act required each utility to consult with MEA regarding the design and adequacy of the programs it was proposing. Each utility is also required to provide an annual update to the PSC and MEA on plan implementation and progress towards meetings the goals. The PSC, in consultation with MEA, must provide an annual report to the General Assembly regarding the status of the programs, a recommendation for the appropriate funding level to adequately fund the programs and services, and the per capita electricity consumption and peak demand for the previous year.

The PSC established a separate proceeding and schedule for each utility's filing. Motions to Intervene were filed by eight to ten parties in each proceeding; the PSC granted all such motions. Comments by the intervenors, as well as a response by the utility, have been filed in each proceeding. The PSC has conducted hearings, each of which has lasted more than a day, on each utility's proposal. According to the Act, in determining whether a program or service encourages and promotes the efficient use and conservation of energy, and therefore whether it should be approved, the PSC must consider (i) the cost-effectiveness; (ii) the impact on rates of each ratepayer class; (iii) the impact on jobs; and (iv) the impact on the environment.

Although the Commission has until December 31, 2008 to issue an Order in each proceeding, several points warrant comment. *First*, four of the five IOUs' plans (Allegheny Power is the exception) meet the Act's goal of a 5 percent peak demand reduction by 2011. By 2015, only Baltimore Gas and Electric Company and Potomac Electric Power Company meet the 15 percent reduction in peak demand. The numbers are even worse for energy consumption. In 2011, only Southern Maryland Energy Cooperative is able to meet the 5 percent reduction in energy consumption; in 2015, no utility's proposal reaches the 10 percent goal. It is clear that more aggressive, innovative programs are required.

Second, there is no current baseline study of Maryland customers that allows the utilities or the regulators to assess the reasonableness of the utilities' assumptions regarding participation rates, necessary rebates, and the like. The participants in these proceedings have urged the PSC to initiate such a study so that all parties have a reasonable baseline to utilize when predicting and evaluating program results. The PSC issued an order on December 1 directing the utilities to collaborate on and issue a request for proposals to initiate a State-wide baseline study during 2009, which will help refine these programs going forward and help ensure they are and remain cost-effective.

Although the Commission has struggled to find and approve the appropriate mix of programs, there is no doubt that energy efficiency and demand response programs yield the greatest bang for the ratepayers' investment buck. Levitan's analysis demonstrates that meeting the EmPower Maryland goals would provide one of the highest levels of economic value

added ("EVA") as compared to business-as-usual. Levitan evaluated four of the five EmPower Maryland plans[60] and "grossed up" their proposed energy reductions to ensure that they would meet the 15 percent reduction by 2015. The "reference case," designed to simulate a business-as-usual approach, assumes only 25 percent of the EmPower Maryland goals will be met. As compared to the reference case, Levitan's "15x15" scenario showed cost savings every year, rising in later years to nearly $500 million per year. However, Levitan assumes that costs will rise as market penetration increases, so that the highest benefit to cost ratio is for the early "low- hanging fruit," the first 25 percent included in the reference case. Annual savings skyrocket under the "peak oil" scenario, to over $1 billion per year in later years, but more importantly, remain strongly positive under the much lower oil price scenario (i.e., the *Federal Outlook* case). According to Levitan, meeting the EmPower Maryland goals would also reduce carbon dioxide emissions nearly three times as much as the annual target under the Regional Greenhouse Gas Initiative. Demand-side initiatives must be an important weapon in Maryland's reliability arsenal, and our work on these programs will continue in 2009 and beyond.

E. The Commission Has Served As An Advocate For Maryland's Energy Interests In The Wholesale Electricity Markets, And The Fight Will Continue.

Approximately 80 percent of the typical Maryland ratepayer's electric bill reflects the wholesale cost of the electricity he or she uses – a cost that, under restructuring, the PSC no longer regulates. But as

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[60] All but SMECO.

reported last year, Maryland's electricity needs have not been satisfied or well-served by the "restructured" electricity markets. Accordingly, the PSC has devoted substantial time, effort and resources to serving as an advocate for Maryland ratepayers at PJM and before the Federal Energy Regulatory Commission ("FERC").

We have focused our efforts over the last year on market rules and pricing issues. Retail electric service and prices in Maryland are affected by prices and practices relating to the provision of generation and transmission at the wholesale level, over which FERC has authority under the Federal Power Act. Currently, suppliers providing generation to serve Maryland load have market-based rate ("MBR") authority, which means that they are allowed to charge rates that are not subject to FERC's approval (based upon its determination that the supplier lacks market power or has sufficiently mitigated its market power in the market to be served). Whether they are established by bilateral contract or by the winning bid in a market run by PJM, rates for wholesale generation sold by suppliers with MBR authority must be just and reasonable under the Federal Power Act.

The wholesale electricity markets are not unbridled market environments – they operate according to rules that can be subject to interpretation and judgment in applying them. When we become aware of rules that are being interpreted or applied unfairly, we have challenged those rules, and we will continue to do so. During 2008, the PSC filed complaints asking FERC to require PJM to lift the exemptions from offer-capping applicable to certain interfaces and generators, and to provide a remedy for unjust and unreasonable generation capacity prices occurring in

the transition to PJM's Reliability Pricing Model ("RPM") capacity construct.

There are several other ways to help support competitive wholesale generation markets. One way to bring more discipline to PJM's generation markets (and to advance Maryland's energy conservation goals) is to ensure that energy efficiency and demand response are part of the bidding process. Demand response has been permitted to bid into PJM's capacity markets, but to date energy efficiency has not. Proposals are pending, and the Commission has participated in FERC proceedings (and PJM stakeholder procedures) on the participation of energy efficiency in PJM's markets. Ensuring that PJM's interconnection procedures will not present an undue barrier to the entry of new generation or merchant transmission projects needed to relieve transmission constraints is another way to support competitive markets and help ensure reliable service at reasonable prices; and the PSC has participated in FERC proceedings and PJM stakeholder procedures in an effort to improve the efficiency of this process.

Another important way to enhance competitive generation markets (and help ensure reliable service at reasonable rates) is to have sufficient regulated transmission available (particularly high-voltage, backbone facilities) to support power transfers. The PSC supports rate incentives that will encourage investment in transmission that will bring regional benefits by increasing import capability, relieving congestion, or improving access to markets by renewable generation. But we also are mindful that while the lion's share of the delivered price for electric service is related to generation, transmission costs are increasing too. We have participated in several incentive

pricing proceedings at FERC in connection with transmission investments by various PJM transmission owners. The PSC consistently has opposed incentive treatment in connection with investments that are needed to ensure local reliability in the transmission owner's distribution territory, since electric companies generally are required to provide reliable service by state statute (as in Maryland).

Even if the transmission investment provides regional benefits, the PSC believes that the incentives must be reasonably connected to the risks involved. Investments in transmission needed to support PJM's markets do not carry a large risk; and PJM's transmission owners have developed much experience and expertise by building transmission facilities for years. Hence, the PSC has opposed large return on equity ("ROE") adders on new transmission investments, unless warranted by sheer magnitude of the project or the utility's use of new technology. This is particularly true if the transmission owner seeks recovery of abandonment costs and construction work in progress ("CWIP").

So far, a FERC majority has awarded incentive ROEs that the PSC opposed as unwarranted in several proceedings, almost always with two of five Commissioners dissenting; and the PSC is seeking rehearing of the FERC majority's orders. Additionally, the PSC has participated in formulary rate proceedings filed by PJM transmission owners outside Maryland. Participation in such proceedings is necessary not only in terms of establishing FERC precedent, but also because Maryland shares some of these transmission costs under PJM's current transmission rate design. Finally, the allocation of the costs of transmission investment in PJM affects Maryland

ratepayers, and the PSC is participating in a judicial review proceeding in support of FERC's order establishing PJM's rate design.

The PSC will continue to play an informed and aggressive role in advocating for Maryland's energy interests in the PJM shareholder process and other PJM fora, and before FERC. This will require additional in-house resources (the PSC lost its last PJM technical expert in large part due to the inability to compete with private sector salaries and needs to build expertise in wholesale electricity markets) as well as outside counsel and experts for large-scale litigation.

F The Commission's Consultants' Analyses Demonstrate That New Generation Will Benefit Maryland Ratepayers.

As discussed in more detail in the Kaye Scholer report, restructuring has failed to stimulate construction of new power plants in Maryland: only 700 MW of new capacity has been added since 2000. Maryland has approved construction of more than 3,000 MW of new generation, but less than 200 MW of that is expected to be in-service by year-end 2009. At the same time, Maryland's generation fleet is aging: 67 percent of the State's total generating capacity over 31 years old, and another 11 percent over 21 years old. Under deregulation, merchant generators were expected to respond to market signals regarding needed generation, but despite high LMPs and capacity payments, Maryland's generation needs are not being met. Indeed, one merchant generator testified before the PSC that no matter how high RPM payments were, it could not finance a new generation project in

Maryland without a PPA for at least ten years.[61] Complicating the situation is the fact that merchant generators and companies owning generation share a vested interest in maintaining high LMPs and capacity payments.

The PSC's consultants explored multiple options for obtaining additional generation in Maryland, and specifically whether each of these options would yield economic benefits for ratepayers when measured against Levitan's baseline Reference Case. Levitan modeled two options for 1,080 MW of combined-cycle gas generation: long-term PPAs with merchant generators and IOU-owned and –operated new construction under traditional cost-of-service regulation. Both Levitan and Kaye Scholer also explored various options for a state power authority, including the construction of new generation. Levitan also modeled solar and wind options.

Stated generally, our consultants' analysis reveals that Maryland ratepayers would benefit from 1,080 MW of additional generation, above and beyond basic reliability needs, and that the economic benefits are roughly equal regardless of ownership and cost-recovery structure. The benefits from further generation, the "overhang" case, are less clear, and the purely economic benefits from renewables even less so:

1. Long-term PPAs.[62] Long-term PPAs have the potential to solve some of the market deficiencies that have led to a deficit of new generation in Maryland and other constrained states. They can provide a guaranteed stream of income to the generation owner, which

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[61] Transcript of October 3, 2008 hearing, Case No. 9149, at 209 (testimony of D. Egan).

[62] See Levitan report at 110-12, Kaye Scholer report at 79-86.

in turn enables project financing and reduces the cost of investment risk built into energy costs. They can allow Maryland to control the timing, location, type and environmental impact of new generation, and to diversify its options as a hedge against market risk. They can encourage new entrants to the Maryland energy market, thereby enhancing competition. Finally, strategic placement of new generation under a long-term PPA could lower LMPs and capacity costs, thus lowering wholesale prices. PJM has provided guidance on preferred sites that provide more reliability "bang for the buck."

Levitan modeled a 20-year PPA between an IOU and a merchant generator, which would entitle the IOU to the market value of 1,080 MW of new capacity (including energy, capacity and ancillary services sales in PJM markets) in exchange for fixed and variable payments to the merchant generator. Fixed payments would include recovery of capital costs, adjusted for the value of the site from years 21 to 30, as well as return on equity. Variable payments would include fuel and non-fuel operating costs. Levitan projected annual savings of roughly $300 to nearly $800 million compared to the "business as usual" reference case. Although there was a small but insignificant increased benefit of IOU-built new generation, after factoring in the risk of cost overruns the long-term PPA may edge out the IOU build. However, long-term PPAs require a great many decisions, including how best to structure the procurement process to stimulate competition, how to ensure lowest price and best terms, whether to contract for capacity and/or energy, how to index the fuel price to allow the developer reasonable flexibility without exposing ratepayers to excessive volatility, how best to encourage the developer to maintain

availability and efficiency, whether to take actual delivery of the capacity/energy from the facility versus "financial" delivery (in which the buyer gets payments equal to the market values of the capacity and/or energy), what performance guarantees should be built in, and the ideal length of the contract, among others. The risks from long-term PPAs include technological obsolescence, fuel costs (although some of this risk is normally allocated through indexing), stranded costs, and discouraging retail suppliers from entering the market.

2. Order new generation to be built by IOUs.[63] Levitan also modeled 1,080 MW of new combined-cycle gas generation built by IOUs in Maryland, subject to cost- of-service regulation. The Commission would have to decide the extent to which the IOUs could pass certain costs of generation on to ratepayers – generally, prudently- incurred capital, operating and management expenses, including the cost of fuel, would be charged to ratepayers, plus a reasonable rate of return. The capacity, energy and ancillary services from the generator would then be sold into the markets and ratepayers would be credited with their value. As compared to the reference case, new IOU-built generation is projected to save between roughly $200 and $800 million per year.[64]

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[63] Levitan report at 108-09, 112-114.

[64] The differences in the projected savings between new generation built by IOUs and new generation "leased" through a long-term PPA results from differences in the assumptions made for pattern of recovery. IOUs are assumed to recover a relatively larger portion of their costs up-front as compared to the out years, whereas merchant generators are assumed to recover costs equally throughout the duration of the PPA.

3. Effect of surplus capacity ("overbuild" or "overhang").[65] Levitan modeled an option under which Maryland attempts to maintain a surplus of capacity through 2018 by frequent additions of capacity (through either of the previous two options). Although Levitan found that this option provided a somewhat higher present value economic benefit than the previous two options, and could save between roughly $300 and $800 million per year, the direct costs are more than twice as high as either of the previous two options. The marginal benefits of the overbuild or overhang scenario over the previous two options do not, in Levitan's opinion, overcome the substantial additional cost ($2.5 billion additional ratepayer funds at risk) relative to the potential additional benefits($350 million).

4. State power authority.[66] Whether or not the General Assembly were to pursue full re-regulation, it could form a state power authority that would give Maryland greater control over new generation, but by putting the State into the electricity business would dramatically increase ratepayers' economic risk. A power authority could reduce capital costs, especially given its tax-advantaged status, but would expose ratepayers to full responsibility for any adverse outcomes, such as fuel volatility, credit market abnormalities, technological obsolescence, and environmental impact, to name a few. Initially, a state power authority would certainly be less efficient than merchant generators or IOUs in developing and managing generation assets. In addition, an authority would require substantial manpower and take a significant

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[65] Levitan report at 114-15.

[66] Kaye Scholer report at 86-88, Levitan report at 178-89.

period of time to develop the infrastructure to manage and operate the generation assets. Without market incentives, a public power authority may not operate over the long run as efficiently as private owners. And at least one study showed that power authorities are less efficient as generation owners than IOUs.[67]

5. Renewable generation: onshore and offshore wind.[68] Delmarva currently has two onshore wind projects in development: Synergics' 60 MW Eastern Wind Energy and 40 MW Roth Rock Wind Energy. Both of these projects have been included in the reference case. BlueWater Wind's 200 MW offshore wind project has not been included in the reference case since its development is contingent on additional sales.

Levitan modeled the addition of 20-year PPAs for total installed onshore wind capacity of 200 MW, added at 40 MW per year from 2011 to 2015, with the costs and benefits apportioned to the IOUs based on load share. Because wind's total installed capacity is heavily discounted for reliability purposes, 40 MW per year is viewed by PJM as only 12 MW per year (its Unforced Capacity or "UCAP").[69] Although onshore wind of this size is too small to offset any other capacity that would need to be added, it does provide potential cost savings of between $10 and $60 million per year. Onshore wind also has positive economic value added when compared to the reference case. Wind also provides a valuable source of renewables to meet Maryland's Renewable Energy Portfolio Standard. The full 200 MW of onshore wind are

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[67] Kaye Scholer report at 87, n. 332.

[68] Levitan report at 142-159.

[69] Levitan report at 146.

projected to reduce carbon dioxide emissions by 267,000 to 487,000 tons per year, roughly one quarter to one half of the yearly Regional Greenhouse Gas Initiative ("RGGI") goal.

For the offshore wind analysis, Levitan used actual BlueWater Wind contract information and assumed that Maryland IOUs would contract for 300 MW of installed capacity, which would allow the 200 MW under contingent contract with Delmarva to proceed, adding a total of 500 MW installed capacity to the region by 2014. Offshore wind, while using a more reliable wind source and producing greater dioxide reductions (747,000 to 975,000 tons per year, as compared to the full-year RGGI target for 2015 of 937,600), is roughly twice as expensive to build and operate and is thus projected to result in economic loss to ratepayers, not a net benefit. Offshore wind may merit a second look if onshore wind development becomes bogged down by local opposition or if fuel costs are extremely high, but the only scenario showing a (slightly) positive economic value added was the "peak oil scenario."

6. Renewable generation: solar power.[70] Levitan modeled full compliance with the Solar Renewable Portfolio Standard, through installation of 1 MW solar installations at large commercial and industrial ratepayers' sites. By 2022, roughly 1,100 MW of solar capacity would be installed, to be used as "behind the meter" capacity that would replace electricity the commercial and industrial ratepayers would otherwise take from the PJM system.

Assuming the continuing existence of investment tax credits (ITC), solar renewable energy credits

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[70] Levitan report at 160-66.

(RECs) and Modified Accelerated Cost Recovery System (MACRS) depreciation, and with no more than 30 percent debt, Levitan calculated that solar power owners could receive a 10 percent return on equity and positive cash flow from year two forward. Changes to the ITC or RECs could make such solar installations impractical unless solar installation costs fall considerably. New thin film technology may indeed cut installation costs, possibly by as much as half.

Levitan also looked at the aggregate effect of such solar installations on ratepayers by assuming ratepayer-backed 20 year PPAs for the energy, capacity and RECs from the facilities. The result was not as favorable. The capital costs and subsidies that must be paid by all ratepayers to fund the RECs, together with the assumption that the Federal ITC value substantially decreases after 2017, result in negative economic value, regardless of oil prices. To the extent that technological progress cuts the cost of rooftop photovoltaic cells at a much faster rate than the 2.5 percent per year contemplated in this study, solar economics may be materially different from the negative economic value reported in the Levitan report.

G. We Cannot Recommend A Strategy Of Condemning Assets And Returning Existing Plants To Cost of Service Regulation.[71]

Given the strong reactions to rate increases in the wake of deregulation, it was perhaps inevitable that some would call for a return to the days when all of Maryland's generation assets were owned by IOUs regulated under cost-of-service regulation. At our

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[71] Kaye Scholer report at 73-78, Levitan report at 167-89.

direction, both Levitan and Kaye Scholer evaluated options for returning generation to cost-of-service regulation. The exercise as a somewhat awkward one: since the fair market value of the Constellation fleet is at issue in a pending Commission proceeding, we directed Levitan to model only the condemnation of Mirant's fleet in Pepco's Maryland service territory. Kaye Scholer took a broader but less in-depth view of the potential benefits and risks of attempting to return all Maryland generation to full cost-of- service regulation. Both assumed that the State would have to use its condemnation powers and compensate the current generation owners at fair market value as of the date the taking occurred.

Levitan's economic analysis reveals that certain ratepayers could benefit from a return to cost-of-service regulation – specifically, the ratepayers in the service territory of the plants being condemned and returned. The precise fair market value of the plants is extremely difficult to set, but even within the range in Levitan's report – which sets the value of the Mirant assets into the billions of dollars – the return to cost-of service regulation yields positive economic benefits to those ratepayers ranging from roughly negative $200 million or positive $200 million in the early years of IOU or state power authority ownership, respectively, to nearly a billion dollars per year in the later years under either IOU or state power authority ownership. The potential savings are greater with higher fuel costs, and conversely there is no positive economic value added with

IOU ownership under the lower fuel cost assumptions. Power authority ownership continues to have positive economic value added even using lower fuel cost assumptions. Viewed in purely economic terms,

then, one can argue that ratepayers would be better off if Maryland returned to cost-of-service regulation.

It is difficult to do justice to these highly complex analyses in an overview, and a mistake to review the economic analysis in a vacuum. Both Levitan and Kaye Scholer caution that a return to full regulation of Maryland's generation is fraught with risks, and they have not calculated the costs of these risks, among them the following very real and practical obstacles:

- Finding the money, billions of dollars, would be a gargantuan hurdle in the best of times. Current credit market conditions only worsen that prognosis;
- As the Maryland Constitution requires the compensation to be agreed upon between the parties or awarded by a jury, a return to full cost of service regulation could quickly become bogged down in contentious litigation. Fair market value would not be discounted for credit woes currently being suffered by some generation owners, but would be based, at least in part, on the expected stream of earnings for the plants' remaining operating lives;
- By reducing wholesale prices, a return to rate-base regulation will deter merchant generation, both conventional and renewable. As the existing generation fleet is aging, this would force the IOUs or state power authority to assume the cost and risks of supplying all new generation in addition to maintaining the existing fleet;

- IOUs or an authority would likely also have to begin managing all of the risks for standard offer service, currently assumed by competitive suppliers. The IOUs or the State could end up with stranded costs, especially for assets regulated into obsolescence due to evolving emissions standards;
- Ratepayers or taxpayers will assume all investment risk. Both Levitan and Kaye Scholer serve up cautionary tales of poor investments in nuclear power that performed poorly and left ratepayers with higher-than-market rates;
- Ratepayers would experience earnings upsides and disappointments relative to the assumptions built into fair market value. If a state power authority assumed ownership of the generating assets, it would experience a steep learning (and hiring) curve as it attempted to build the skilled staff necessary to effectively operate and manage them. Outsourcing the management and operation, either temporarily or permanently, could fill the need for skilled labor but result in additional costs; and
- The Maryland fleet is an aging one, and taking back the existing fleet would invest billions of dollars in old plants rather than investing in new, cleaner plants.

We cannot reconcile the perhaps visceral appeal of full re-regulation with the very real obstacles to and consequences from a strategy designed to turn back the clock. As economic and financial conditions change, we believe that ratepayers are better served if

the Commission retains the ability – which it has now, under current law – to direct and guide the construction of future generation in Maryland to serve the best interests of Maryland ratepayers. Although we can model positive economic benefits to ratepayers from a return to full cost-of-service regulation, the transactional and other costs to ratepayers far outweighs those potential benefits in our judgment – and would commit enormous resources to a retrospective strategy rather than a prospective one. Accordingly, we cannot recommend that the General Assembly pursue full re-regulation. Instead, we recommend that any legislation regarding "re-regulation" expand the Commission's authority to re-regulate, in our sense of the term, in a measured, rational and incremental way.

V. CONCLUSION

This represents the Public Service Commission's Final Report to the General Assembly pursuant to Senate Bill 400. We look forward to briefing the General Assembly on these issues and in continuing our work to take control of Maryland's electricity future.

STATE OF MARYLAND
PUBLIC SERVICE COMMISSION
[SEAL]

[PLANTIFF'S EXH. NO. P002]

Case No. 9214

December 8, 2011

IN THE MATTER OF WHETHER NEW GENERATING FACILITIES ARE NEEDED TO MEET LONG-TERM DEMAND FOR STANDARD OFFER SERVICE.

NOTICE OF APPROVAL OF AMENDED REQUEST FOR PROPOSALS FOR NEW GENERATION TO BE ISSUED BY MARYLAND ELECTRIC DISTRIBUTION COMPANIES

To Parties of Record and Interested Persons (via electronically):

On September 29, 2011, the Public Service Commission of Maryland ("Commission") issued a Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies. Attached to that notice was a Request for Proposals ("RFP"), inviting interested persons to submit proposals to the Commission to construct new generation facilities that would produce and sell electricity to Maryland's regulated electric distribution companies ("EDC").

On October 21, 2011, the Commission held a pre-bid conference to answer questions concerning the RFP.

After that meeting, the Commission received numerous questions and comments about the RFP. As a result of those questions and comments, the Commission decided to modify several aspects of the RFP including extending the proposal due date to January 20, 2012; encouraging each respondent to submit two proposals one for fixed gas price offering and another proposal for a variable gas price offering; and requiring each respondent to note in its proposal whether it plans to demonstrate its financial strength to construct the new generating facilities by relying on the financial commitment of a parent or other company.

Accordingly, the Commission requires that each Of the Maryland EDCs[1] issue the enclosed RFP immediately and the Commission Staff to post the amended RFP on the Commission's website.

By Direction of the Commission,
/s/ David J. Collins
David J. Collins
Executive Secretary

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[1] The Maryland electric distribution companies that will be required to issue the amended RFP for Generation Capacity Resources under Long-Term Contracts are Baltimore Gas and Electric Company ("BGE"), Delmarva Power and Light Company ("DP&L"), the Potomac Edison Company, and Potomac Electric Power Company ("Pepco").

REQUEST FOR PROPOSALS FOR GENERATION CAPACITY RESOURCES UNDER LONG-TERM CONTRACTS

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REQUEST FOR PROPOSALS FOR GENERATION CAPACITY RESOURCES UNDER LONGTERM CONTRACTS

1 INTRODUCTION

Pursuant to Sections 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, the "Customer Choice Act") of the Maryland Public Utilities Article, Annotated Code of Maryland ("PUA") the Maryland Public Service Commission ("PSC" or "Commission") hereby directs Baltimore Gas and Electric Company ("BGE"), Delmarva Power and Light Company ("DP&L"), The Potomac Edison Company ("PE"), and Potomac Electric Power Company ("Pepco") (collectively referred to as the Maryland electric distribution companies or "EDCs") to issue this Request For Proposals ("RFP") for Capacity and Energy[2] This RFP supplements other reliability

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[12] PUA § 7-510 provides for the phased implementation of customer choice. PUA § 7-510(c) details the obligations of electric companies and the Commission in that regard. PUA § 7-510(c)(4)(ii)1.B provides that "Under the obligation to provide standard offer service ...the Commission, by regulation or order, and in a manner that is designed to obtain the best price for residential and small commercial customers in light of market conditions at the time of procurement, and the need to protect these customers from excessive price increases... may require or allow an investor-owned electric company to procure electricity for these customers directly from an electricity supplier through one or more bilateral contracts outside the competitive process." PUA Article § 7-510(c)(4)(ii)2.A allows, at the Commission's direction, an investor-owned electric company to solicit bids "to supply anticipated standard offer service load for residential and small commercial customers as part of a portfolio of blended wholesale supply contracts of short, medium or long terms and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner." PUA § 7-510(c)(6) permits the Commission to require an investor-owned electric

initiatives undertaken by the Commission in Case 9149.[2]

The purpose of this RFP is to ensure the continued, long-term reliability of the electricity supply to Maryland customers by mitigating key risks faced by the State. During the Commission's Summer 2007 Electricity Planning Conference, PJM Interconnection L.L.C. ("PJM") first reported to the Commission the possibility of power supply shortages on hot summer days beginning in 2011. In 2008, PJM produced analysis that showed shortfalls of up to 1,500 MW depending on assumptions regarding load, generating portfolios, and whether various transmission lines (most notably the Trans-Allegheny Interstate Line ("TrAIL")) would be in service as scheduled.

Since then, no new generation resources of any consequence have come on line in Maryland. In the near term, demand has abated and load growth forecasts have been revised downward as a result of broader economic conditions. Nevertheless, longer-term concerns about future demand, the age and efficiency of Maryland's generation fleet, Maryland's ongoing need to import electricity from other states to meet demand, and evolving environmental awareness and regulations all cause the Commission to remain concerned about the adequacy of the State's

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company to construct, acquire or lease, and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply.

[2] *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland.*

generation resources to serve the long-term anticipated demand for electricity.

The RFP seeks proposals for resources specifically targeted to address and mitigate these key risks faced by the State. These risks include:

- *The risk that load forecasts take a sudden upswing.* Load forecasts can swing by as much as 450 MW in a year for a single utility — this is about the size of one combined-cycle facility. On a statewide basis, load estimates have changed in one year by as much as the capacity of two new combined-cycle plants.
- *The risk that EPA regulations could cause large-scale retirements of generation facilities on which Maryland relies, particularly facilities located in states that have had less rigorous state environmental laws and regulations than Maryland has.* Multiple sources estimate that the PJM area could see several gigawatts worth of retirements. In the most recent RPM Auction, an additional 6,900[3] MW of coal-fired capacity failed to clear as compared to the year before.
- *The risk that State and Federal emissions legislation could raise the cost of baseload generation.* The threat of EPA regulations is estimated to have raised the cost of capacity in the most recent RPM auction by $60 to $80/MW-day.[4] Maryland also has strict emissions reductions goals and relies heavily on coal-fired

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[3] PJM 2014/2015 RPM Base Residual Auction Results Report. http://www.pjm.com/markets-andoperations/rpm/rm-auction-user-info.aspx#Item08 posted 5/13/2011.

[4] *Id.*

power. Future Federal or State taxes on emissions, whether via a direct tax or a cap and trade system, will only add to the cost of coal generation and may force more retirements.

- *The risk that key transmission projects will not be completed as scheduled.* Maryland is highly dependent on transmission to import power, importing roughly 30% of its needs each year.[5] Should key upgrades fail to be completed on time, Maryland could face reliability problems.
- *The risk that demand response resources will not continue to grow at their current pace or that market rules supporting demand response will limit the extent to which those resources can participate in PJM's capacity market.*
- *The risk represented by PJM's estimate that ten's of thousands of new renewable resources would need to come on-line in the next decade to meet PJM State Renewable Portfolio Standards.* Because of the variable nature of their output, these new facilities would increase the need for regulation services from existing and new conventional generation.
- *The risk that Maryland is not in a position to benefit if shale gas keeps natural gas prices low.* This risk reflects the fact that about 90% of Maryland generation comes from coal- and nuclear-fired plants.[6]

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[5] EIA 861 Data averaged from 2005 through 2009. http://www.eia.gov/cneaf/electricity/page/eia860.html. Accessed 9/21/2011. Calculations assume 8% losses.

[6] *Id.*

- *Finally, the risk that RPM will not attract enough new capacity to address these risks effectively, whatever the level of need turns out to be.* RPM has failed to attract new generation in the State to mitigate these longer-term reliability concerns, and RPM's signal remains unable to anchor the financing new generation development requires. Since the beginning of the RPM market, the average clearing price in the Southwest MAAC ("SWMAAC") zone (the zone which contains BGE and Pepco) has been about double that of the rest of the PJM RTO (the unconstrained portion of the RTO). Despite this price signal, practically no generation has been built in Maryland. Between the 2008-09 and 2013-14 RPM Auctions, only 242 MW of new capacity "cleared" (i.e., was selected to provide capacity) in the SWMAAC zone.[7] Since 2006, only 202 MW of generation has actually come online in the State.[8]

Although the Commission recognizes and appreciates PJM's role in planning regional transmission solutions, Maryland law directs this Commission to ensure an adequate and reliable supply of electricity to Maryland citizens. Where that supply may fall short, Public Utilities Article § 7-510(c)(6) authorizes this Commission to require investor-owned electric companies in Maryland to "construct, acquire or lease,

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[7] Monitoring Analytics testimony in response to Administrative Docket PC22, "IN THE MATTER OF THE RELIABILITY PRICING MODEL AND THE 2013/2014 DELIVERY YEAR BASE RESIDUAL AUCTION RESULTS." Submitted October 4, 2010.

[8] Data gathered from PJM's generation queue listed as "In-Service" between 2006 Q3 and 2011 Q3.

and operate generating facilities in order to meet long-term anticipated demand in the State for standard offer service and other electricity supply."

Because market forces have not produced new generation in our region, the Commission may need to invoke its authority under § 7-510(c)(6) if the record in this case demonstrates long-term risks of a projected capacity shortfall in an upcoming Delivery Year and that ordering the construction, acquisition, lease or operation of additional capacity resources would satisfy the long-term anticipated demand in Maryland for Standard Offer Service or other electricity supply.

Throughout this RFP, capitalized terms used but not defined herein have the meanings ascribed to such terms in PJM's Reliability Assurance Agreement ("RAA") or PJM's Open Access Transmission Tariff ("OATT"), or in the model agreement (the Agreement) for fixed/indexed pricing (*see* Section 4 below). The Commission will evaluate all proposals submitted in response to this RFP.

The Commission is solely responsible for determining contract awards under this RFP, and may authorize one or more of the Maryland EDCs to enter into a long-term Contract for Differences as Buyer. Each Generating Capacity Resource will be signed to a single contract with a single EDC.

2 PRODUCTS REQUESTED

2.1 PRODUCT DEFINITION

The Commission is requesting proposals for Products that must include Capacity and Energy. The Products must be derived from Generation Capacity Resources (as defined in the PJM RAA) that will be located inside the Southwest MAAC Locational

Deliverability Area. Generation Capacity Resources must be new, natural gas-fired units.

2.1.1 DISPATCHABLE GENERATION CAPACITY RESOURCE

The hourly Energy output from a Dispatchable Generation Capacity Resource will be dispatched in the PJM Day Ahead Market ("DAM") or Real Time Market ("RTM") based on an offering that reflects actual fuel costs plus non-fuel variable operation and maintenance ("O&M") costs, and by the actual availability of the unit or units which make up the Dispatchable Generation Capacity Resource. Each such unit shall be offered into the DAM or RTM by submitting a cost-based offer. Suppliers shall also offer relevant Ancillary Service products into the PJM markets so as to optimize net revenues.

2.2 TERM OF AGREEMENT

Respondents must submit proposals to commit Generation Capacity Resources for an initial term of up to twenty years beginning no earlier than June 1, 2015 and no later than June 1, 2017.

2.3 PRODUCT QUANTITY

Respondents may offer Products in any quantity from Generation Capacity Resources not to exceed 1,500 MW on an installed capacity basis. The quantity of Capacity offered by a Respondent must be constant over the contract term. The Commission may award one or more contracts to one, or more Suppliers •for Products derived from Generation Capacity Resources up to, but not to exceed, a total installed capacity of 1,500 MW The Commission reserves the right to acquire more supply or reject all submissions to this

RFP if in its sole discretion the Commission determines that such actions are in the public interest.

3 CONTRACT STRUCTURE

The Supplier will own and operate the Generation Capacity Resource committed in response to this RFP. The Supplier will remain responsible for O&M of the Generation Capacity Resource, including offering and scheduling the Generation Capacity Resource in PJM's DAM and/or RTM. In accordance with Section 3.2 (Payment), the Buyer will enter into a financial arrangement with the Supplier in which the physical delivery to the EDC of the Capacity, Energy and Ancillary Services is not required. Rather, the obligation of physical delivery and related performance of the Capacity, Energy and Ancillary Services, including the Offer Requirements in the Reliability Pricing Model (RPM) and the DAM and/or RTM will be an obligation of the Supplier to PJM in accordance with the PJM RAA, the PJM Operating Agreement and OATT. The financial arrangement between the Buyer and a Supplier for Capacity and Energy will be a Contract-for-Differences ("CfD"). Hence, the delivery of Capacity and Energy will be settled financially rather than physically, thereby providing compensation to Supplier for Capacity and Energy. Pricing for Capacity and Energy from Dispatchable Generation Capacity Resources will be based on a combination of a firm and indexed pricing basis, as described in Section 6.1, k.

3.1 RESOURCE REQUIREMENTS

The Generation Capacity Resources provided must meet the following requirements:

a. The Capacity from the Generation Capacity Resource(s) must not have cleared any prior PJM Base Residual Auction ("BRA");

b. Capacity from the Generation Capacity Resources must meet all requirements to qualify for the BRA. The Supplier must offer the Capacity from the Generation Capacity Resource into the BRA for the Delivery Year that begins on the first June 1 following the target Commercial Operation Date of the Generation Capacity Resource(s). The Supplier must offer such Capacity into the BRA in accordance with BRA rules and regulations as they exist throughout the term of the Contract. The Supplier will not be paid for any year in which the Supplier's Generation Capacity Resource does not clear the BRA;

c. The Supplier must keep separate in the PJM eRPM system the Generation Capacity Resources committed as a result of this RFP from other Generation Capacity Resources of the Supplier; and

d. The Supplier must provide the Buyer read-only access to its PJM eRPM system, Market Settlements Reporting System ("MSRS"), and Load Response system accounts for the Generation Capacity Resource(s) committed as a result of this RFP. Such accounts shall be used for the sole purpose of verifying contract performance.

3.2 PAYMENT

For the Supplier's Capacity and Energy, the financial arrangement between the EDC and the Supplier will be a'CfD between a) the Supplier's contract Capacity price and the RPM clearing price

applicable to the Maryland EDC's service territory, and between b) the Supplier's contract Energy price and the hourly PJM nodal Locational Marginal Pricing ("LMP") in the PJM DAM and/or RTM, as applicable, at the point of delivery into the EDC's service territory. For illustration purposes only, a sample CfD transaction for Capacity and Energy from a Dispatchable Generation Capacity Resource is shown in Attachment 1. The schedule for billing net amounts of CfD obligations due to either party will be monthly.

3.3 NON-PERFORMANCE PENALTIES

Penalties for failure to provide proposed Products or to meet proposed heat rate and availability standards are defined in the Agreement (Attachment 8).

3.4 CREDIT REQUIREMENTS

All Respondents must provide financial information as described in Section 6.1 below. The Commission will determine if a Respondent and its Guarantors meet minimum standards of financial integrity.

General requirements for construction and operating phase security are described in Attachment 2. Specific preferred terms are presented in the Agreement (Attachment 8).

4 AGREEMENT

A model Agreement to be executed as a result of this RFP is provided as Attachment 8. The Agreement is meant to memorialize the terms and conditions described in this RFP; to the extent there is any conflict, this RFP controls and the final Agreement will be revised to comply with it. The Agreement contains the parties' rights and obligations for providing and receiving Capacity and Energy. While

suggested changes to the model Agreement will be considered, offers which conform to all major terms will receive preference in the evaluation.

5 ELIGIBILITY OF RESPONDENTS

5.1 ELIGIBILITY REQUIREMENTS

A Respondent is eligible to offer a proposal if, in a timely and complete fashion, the Respondent submits the following Eligibility Documents by the respective due dates indicated in Section 8:

a. A non-binding Expression of Interest Form, provided as Attachment 3;

b. An executed copy of the certification that the Generation Capacity Resource which the Respondent plans to commit under this RFP did not clear any prior PJM capacity auction, provided as Attachment 4;

c. An executed copy of the certification that the Respondent meets the RIM membership requirements, provided as Attachment 5;

d. An executed copy of the Binding Offer Agreement, provided as Attachment 6; and

e. An executed copy of the Confidentiality/Non-disclosure Agreement, provided as Attachment 9. A Respondent and the EDC issuing the RFP will be required to execute the Confidentiality/ Non-disclosure Agreement. Once the agreement is received from the Respondent, the EDC will complete the execution of the agreement and send a copy of the fully executed agreement to the Respondent and to the Commission by mail, courier service, or appropriate electronic means.

5.2 AFFILIATE PARTICIPATION

An unregulated affiliate of an EDC may participate as a Respondent in this RFP process. The unregulated affiliate and its affiliated EDC will be subject to the provisions of the Code of Maryland Regulations, Title 20, Subtitle 40- Electric and Gas Companies-Affiliate Regulations. Unregulated affiliates will be subject to the same rules and receive the same treatment as third-party bidders.

6 PROPOSAL

6.1 PROPOSAL CONTENT Proposal content must include:

a. Summary description of the Respondent, including:

- Name
- Legal form (*e.g.*, sole proprietorship, partnership, limited partnership, joint venture, corporation, etc.)
- Principal contact information (name, mailing address, telephone number, fax number, and email address)
- Date of establishment
- State of incorporation
- Residency of organization
- Organization chart of the Respondent's company showing parent company, subsidiaries, and affiliates
- If the Respondent proposes to rely on the commitment from a parent or other company to demonstrate its financial strength, then

the above information must also be provided for that company.

- If the Respondent is a joint venture or consortium, the above information must be provided for each member of the venture or consortium
- Description of technical and managerial experience and qualifications in the areas of permitting, development, financing, construction, and operation of electric generating facilities, including experience in the control of cost overruns
- Description of familiarity and experience with PJM markets and requirements for membership status with PJM
- Description of financial condition and evidence of creditworthiness, including senior unsecured long-term debt credit ratings from major rating agencies and the most recent two years' audited financial statements for Respondent and/or a parent or other company on which Respondent will rely to demonstrate its financial strength. For the latter, a letter must be provided by that company indicating their commitment to the development of the proposed project and to assist the Respondent in meeting all credit and other requirements under the Agreement.
- Description of other generation owned or under contract within the State of Maryland, including resources currently under development or construction

- Description of other principal team members, such as Engineering, Procurement, and Construction ("EPC") and Operations and Maintenance Contractors, if any, and relevant experience of those entities
- Description of defaults, non-compliance, fraud or criminal misconduct by a Respondent or any of its officers, directors, partners, guarantors, or affiliates with any obligations relating to power or natural gas sales or purchases or transmission obligations
- Description of instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was the subject of an investigation or a proceeding relating to conversion, fraud, mis-representation, false statements, unfair or deceptive business practices, business theft, anti-competitive acts or omissions or collusive offering or other procurement- or sale-related irregularities
- Description of any instances in which a Respondent or any of its officers, directors, partners, guarantors or affiliates was convicted of any felony, or any crime relating to the sale of power, natural gas or transmission, conversion, theft, fraud, business fraud, misrepresentation, false statements, unfair or deceptive business practices, anti-competitive acts or omissions or collusive offering or other procurement or sale-related irregularities

b. Summary description of the proposed Generation Capacity Resource, including:

- Description of site and surroundings, including description of site control (ownership, contractual arrangements, etc.)
- Map showing location of site and interconnection facilities
- Electric interconnection point with transmission system
- Interconnection status and cost estimates
- Copies of transmission interconnection studies conducted
- Nominal capacity
- Technology type
- Size of unit(s)
- Number of unit(s)
- Site plan drawing showing layout of major equipment and structures
- Description of Ancillary Services capability
- Commercial Operation Date and detailed critical path schedule, including timelines for permitting, engineering, procurement, construction, startup, and commercial operation
- PJM market participation eligibility
- Proposed contract term

c. Fuel Supply Plan / Energy Resource Assessment

- Fuel type and secondary fuel, if applicable
- Liquid fuel storage capacity on-site or contracted for, fuel replenishment rate, and oil tankage refill logistics, if applicable

- Natural gas interconnection points, source of supply, interstate and local transportation arrangements
- Character of service on interstate pipelines, including definition of primary firm, secondary firm, and/or interruptible transportation rights with specific designation of receipt and delivery points on each pipeline segment on which Supplier has an entitlement
- Imbalance resolution arrangements with a gas utility, marketer or third party
- Identification of storage, Park & Loan, other arrangement providing for natural gas scheduling flexibility
- Other fuel supply and transportation arrangements

d. Permitting Plan

- List of any applicable federal, state, and local permits, certifications, and approvals required to construct and operate the Generation Capacity Resource and a projected timeline for securing any applicable federal, state and local permits
- Current status of all permits, certifications, and approvals required to construct and operate the Generation Capacity Resource including electric and gas interconnections
- Documentation of community support for Generation Capacity Resource

e. Capital Cost Estimate: Additional detail must be provided in the form of a narrative supporting the scope of and level of confidence

in the estimate. The estimate should include interconnection costs and all related costs such as, but not limited to, studies, permits, design, and construction costs.

f. Financing Plan: Description of plan and demonstration that the proposed Generation Capacity Resource can be financed. The sources of debt and equity investment must be provided. Anticipated usage of federal loan guarantees and/or production or investment tax credits available under federal programs must be identified, if applicable. Other sources of tax benefits attributable to accelerated depreciation benefits for specific Generation Capacity Resource technology types must be stated. The Financing Plan shall include a detailed pro forma cash flow statement showing the financial viability of the Generation Capacity Resource.

g. Ratepayer Benefits: Description of the reliability and direct economic benefits to Maryland ratepayers as a result of the Generation Capacity Resource.

h. State of Maryland Benefits: Description of other reliability, economic, socioeconomic and environmental benefits that are likely to be realized in Maryland as a result of the Generation Capacity Resource, *e.g.*, construction jobs, permanent employment during the operating period, tax effects, community improvements, other.

i. Contract: State any exceptions to the contract terms appearing in the Agreement (Attachment 8) or state that contract tennis are acceptable in their entirety.

j. Detailed Operating Parameters

- Complete the worksheets appearing in Attachment 7 and provide any narrative that will facilitate the Commission's analysis of Generation Capacity Resource performance.
- The Commission reserves the right to seek additional information from Respondents to support its technical assessment of the Generation Capacity Resource submissions.

k. Pricing Proposal

- Respondents are invited to submit multiple pricing options for the same Generation Capacity Resource. Provide a narrative description of each separate pricing option offered with respect to the Generation Capacity Resource. The pricing option for each should include the total pricing provisions for the Capacity and Energy produced by the Generation Capacity Resource over the contract term. Respondents are encouraged to provide pricing options that may also include contract extensions unilaterally exercisable by the Buyer. Principles for Fixed/Indexed pricing are described in detail in Exhibit F of Attachment 8 and on the pricing worksheets in Attachment 7 (Dispatchable Generation Capacity Resource).

- Respondents are encouraged to submit two bids: one specifying a fixed fuel price and one specifying a variable fuel price. Either type of bid should specify a term of up to twenty years. To qualify as a fixed fuel price bid, a minimum of 5 years of fixed fuel prices must be offered.
- Pricing may be specified for Capacity in the following form:
    1) A Fixed/Indexed offer based on principles defined in Exhibit F of Attachment 8, as a combination of:
        - A schedule of firm, fixed prices expressed as $/MW-day of Unforced Capacity ("UCAP") provided, for each Delivery Year (June 1 to May 31) of the contract term;
        - A fixed base price, expressed as $/MW-day of UCAP provided, and a formula for adjustment for each Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator;
- Pricing for Energy from a Dispatchable Generation Capacity Resource offered on a Fixed/Indexed basis as described in Exhibit F of Attachment 8 shall consist of a heat rate call option with any or all of the following components:
    1) A non-fuel variable component expressed as:
        - A schedule of firm, fixed prices expressed as $/MWh of energy delivered,

for each Delivery Year (June 1 to May 31) of the contract term, and/or;

- A fixed base price, expressed as $/MWh of energy delivered, and a formula for adjustment for each capacity Delivery Year based on a broad-based, published inflation index such as CPI or GDP deflator.

2) A fuel component expressed as the product of:

- a defined annual heat rate (MMBtu {Higher Heating Value (HHV)}/MWh) and;
- a fuel price ($/MMBtu) based on either a) a published daily index plus defined adjustments for transportation and local delivery service adder(s) or b) a fixed fuel price if it has been offered by the Supplier, which is applied to energy output in each hour.

3) A start-up component consisting of:

- A fixed base price, expressed as $/unit start, with a formula for adjustment for cach capacity delivery year, based on abroad-based, published inflation index such as CPI or GDP deflator, and;
- A fuel component defined as the product of a specified start-up fuel amount in MMBtu/unit start and either a) a fuel price ($/MMBtu) based on a published daily index plus specified adjustments or b) a fixed

fuel price if it has been offered by the Supplier.

6.2 SUBMITTAL OF PROPOSALS

Proposals from Respondents are due no later than 3:00 p.m. Eastern Prevailing Time (EPT), on January 20, 2012. Submit one (1) bound original of the proposal, five (5) bound copies, and an electronic version in MS Word or Excel format as a PDF file on a CD or flash drive through express mail (*e.g.*, FedEx, UPS, etc.) to the following name and address:

Name: Dolline M. Serra
Address: 6 St. Paul Street, 16th Floor, Baltimore, MD 21202 Phone: 410-767-8009

6.3 PROPOSAL CONFIRMATION

The Commission will confirm receipt of a Respondent's proposal by email. As indicated in each proposal, the Respondent will provide a contact name, phone number, and email address which will be used for the receipt confirmation.

Eligibility documents are due by 3:00 PM EPT on the deadline indicated in section 8. The eligibility documents shall be submitted in the same manner and format and to the same address as that specified above for submission of proposals. The Commission will confirm receipt of a Respondent's eligibility documents by email.

6.4 EXPIRATION OF PROPOSALS

Proposals shall expire the earlier of the time Commission notifies the Respondent that its proposal has been rejected in full or part, or at midnight EPT on April 30, 2012. All Product pricing submissions must remain binding until midnight EPT on April 30, 2012.

6.5 EVALUATION OF PROPOSALS

The Commission will evaluate the Generation Capacity Resource proposals as laid out below to determine whether the proposals will enhance electric service reliability and are in the best interests of ratepayers. The evaluation will consist of a) an initial screen to ensure the bid meets the minimum threshold criteria, b) for all bids that pass this screen an initial shortlist evaluation consisting of a price and non-price score, c) for the top bids in the initial shortlist evaluation, a final shortlist evaluation using production cost modeling, and d) the selection of the top bids from the final shortlist to sign agreements with one or more EDCs.

The Commission may employ an independent monitor to assist in evaluating the bids. The Commission will evaluate all responsive proposals based on quantitative as well as qualitative evaluation criteria. After the proposals are submitted, the Commission may request additional information from Respondents in furtherance of the Commission's technical evaluation. A Respondent's failure to provide additional information on a timely basis may cause the Commission to reject such Respondent's proposal.

6.5.1 MINIMUM THRESHOLD CRITERIA

In submitting proposals for the Commission's evaluation, Respondents must demonstrate that the proposed Generation Capacity Resource meets certain minimum threshold criteria related to the Respondent's managerial, technical, and financial capabilities. The minimum threshold criteria are those factors that are either explicitly mandated in this REP or are otherwise deemed by the Commission to be integral to the successful development of the Generation

Capacity Resource and, in particular, the delivery of reliability and economic benefits for Maryland ratepayers. The minimum threshold criteria are designed to be straightforward factors that can be assessed by the Commission in an initial review of the proposals and therefore do not require extensive economic, commercial, or engineering analyses. Proposed Generation Capacity Resources that do not comply with each of the minimum threshold requirements will not be considered by the Commission for further evaluation.

The minimum threshold criteria are as follows:

1. The proposal includes all of the Eligibility Requirement documentation described in Section 5.1.
2. The Respondent possesses sufficient technical, managerial, and financial capability to implement the proposal in accordance with the Commission's requirements.
3. Proposals from an affiliate of a Maryland EDC must demonstrate that the Generation Capacity Resource will not receive any form of cross-subsidization by the EDC or other regulated affiliated entity.
4. Proponents must demonstrate a legal entitlement to each site on which a Generation Capacity Resource is proposed. Proof can be in the form of current ownership of the property, a current long-term lease on the property, or an option to lease or buy the property that can be exercised at any time until the Commission issues its final decision on the proposal and a contract is executed. Respondents must also demonstrate a legal entitlement to any required

right-of-way to access electrical and fuel interconnection points.

5. The proposed Generation Capacity Resource must be capable of being interconnected to the System and located within the Southwest MAAC Locational Deliverability Areas (LDA) as defined by PJM.

6. Respondents must provide proposals for building new natural gas-fired Generation Capacity Resources. Existing generation capacity does not satisfy threshold procurement criteria set forth in this RFP nor does an uprate of existing capacity. However, proposals for new units of this technology type to be constructed on the same site as existing facilities will be considered in accord with the minimum threshold requirement set forth in this RFP, but only for the capacity associated with the new unit(s) at the existing facility.

7. Respondents must submit proposals that commit Generation Capacity Resources beginning no earlier than June 1, 2015 and no later than June 1, 2017.

8. Respondents or their guarantors must present a financing plan for their unit, which demonstrates how the respondent will fund construction of the unit and how they will provide for the credit requirements in the contract-for-differences. The Respondent must provide a letter of intent to provide credit security within 30 days of being selected to the final shortlist.

9. While suggested changes to the model Agreement (Attachment 8) will be considered, offers

which conform to all major terms will receive preference in evaluation. Changes which shift risk to ratepayers are discouraged.

6.5.2 COSTS AND BENEFITS TO RATEPAYERS

Each proposed Generation Capacity Resource that meets the minimum threshold criteria will be scored for both price and non-price factors as laid out below.

Respondents must submit an initial cost estimate with their bid. The Commission may seek clarification from Respondents regarding such cost estimates. Respondents who are selected to the final shortlist will be asked to provide a "best and final" offer. All offers will be binding.

The Commission will evaluate the size and quality of the reliability enhancement and economic benefits associated with each proposal from Respondents that satisfies the minimum threshold criteria. Subject to the 1,500 MW limit available for long term contracts, the Commission also will consider the impact of different Generation Capacity Resource portfolios on the expected net benefits realized by the ratepayers of Maryland's EDCs.

6.5.3 INITIAL SHORTLIST - NON-PRICE SCORES

Each proposal that meets the threshold criteria will also be subject to a qualitative evaluation based on an overall assessment of its merits. Qualitative factors will account for 30% of the final score given to each bid submission. There will be three categories: (1) Development Feasibility and Risk; (2) Site Control and Permitting; and (3) Operational Viability and Risk Impacts. Each category will account for up to 10 percentage points. These categories are detailed below:

1. Development Feasibility and Risk (10%) — Bids will be evaluated based on the quality of their proposal, their responsiveness to the information requested and their ability to demonstrate that the project can be reasonably developed within the appropriate timeframe and at the cost proposed. This category will be broken into three sub-categories which examine the feasibility of the following items: critical path schedule and cost proposal, including the strength of the financial plan (5%), engineering design and technology (2.5%) and fuel supply and transportation strategy (2.5%).

2. Site Control and Permitting (10%) — Bids will be evaluated given the detail provided concerning the breadth and depth of permits needed, the status of these permits, and a schedule to obtain these permits. Bids demonstrating no risk will receive the highest values. This category will be broken down into three sub categories which evaluate the Respondents' progress in the following areas: permits required (5%), access to operational utility supply (water, sewage, etc.) (2.5%), right of ways (2.5%).

3. Operational Viability Risk Impacts and Benefits (10%) — Bids will be evaluated based on the depth and quality of their proposal in the following four areas: compliance with model contract (2.5%), environmental compliance strategy (2.5%), O&M plan (2.5%), and benefits to the State of Maryland (2.5%).

The Commission will apply these criteria to all proposals that satisfy the minimum threshold criteria and include the analysis in the selection of an initial shortlist.

6.5.4 INITIAL SHORTLIST - PRICE SCORES

The price score of the bid will account for up to 70% of the final bid score. The price score will be based on a comparison of the levelized net present value (NPV) of the offer.

This value will be the forecasted annualized cost of a bid developed by adding together (a) the requested capacity payment and fixed O&M payment; and (b) operating costs, consisting of the annual fuel costs of the plant based on the units' predicted capacity factor, heat rate, fuel price, variable O&M and start-up costs. Fuel prices will be determined using either (a) a published daily index plus defined adjustments for transportation and local delivery service adder(s) or (b) a fixed fuel price if it has been offered by the Supplier. The annualized costs will be discounted to present day and compared on a $/MWh basis.

The price score will then be determined by comparing the dollar per MWh levelized cost of the bid to the average dollar per MWh levelized cost of all bids. Bids that cost 80% of the average cost or less will receive 70 points. Bids that cost 140% or more of the average cost will receive 0 points, results in between will be linearly interpolated. The Commission may adjust the 80/140 parameters to ensure that the 70/30 split between price and non-price scores is maintained. The bids with the highest total (i.e. price plus non-price) scores will be selected to the Initial Shortlist. Up to two times the desired need (i.e. 3,000 MW) may be selected for the Initial Shortlist. The Commission may raise this target quantity at their discretion.

If less than 1,000 MW of fixed fuel price offers are selected in the initial ranking of 3,000 MW, a separate ranking of only fixed fuel price offers will be conducted

to select additional bids to meet the 1,000 MW goal. In this separate ranking, 1.5 bonus points will be awarded and added to the price score for each year over five years that a fixed fuel price is offered. Fixed fuel price offers will then be ranked, and the offers with the highest combined price and non-price scores will be selected to the Initial Shortlist. For example, if no fixed fuel price offers arc selected for the 3,000 MW of the Initial Shortlist, then the separate ranking will be used to select 1,000 MW of only fixed fuel prices offers. In this case, the total Initial Shortlist would be 4,000 MW.

6.5.5 FINAL SHORTLIST ANALYSIS

The bids on the Initial Shortlist will move on to the Final Shortlist Analysis. Each bid will be modeled in a production cost model to determine their cost to ratepayers throughout the term of the contract. The cost of each bid will be assessed based on changes in key risk factors such as natural gas prices, environmental or other compliance costs and load. The bid(s) that produces the lowest-cost solution for ratepayers when accounting for risk will be the selected to the Final Shortlist. The Commission may then direct the Maryland EDCs to finalize contracts with one or more entities from the Final Shortlist.

7 COMMUNICATIONS

This RFP, updates to this RFP, and other relevant information will be posted on the Maryland Public Service Commission's website at www.psc.state.md.us. The information may be found under "Documents", "Search Cases". Enter "Case No. 9214." Questions regarding this RFP may be submitted to the Commission until the deadline indicated in Section 8. All questions regarding this RFP must be directed to

Dolline Serra via email at dserra@psc.state.md.us. No questions will be accepted by telephone. The Commission will respond to questions as soon as practicable. Questions and responses will be posted on the Maryland Public Service Commission's website. Questions will be redacted as necessary to preserve the confidentiality of Respondents.

8 SCHEDULE FOR RFP PROCESS

In order to preserve a possible offering into the May, 2012 Base Residual Auction ("BRA") for the 2015-2016 delivery year, the RFP schedule is as follows. Please note that this schedule is subject to change.

ACTIVITY	DATE
RFP issued	Thursday, September 29, 2011
Pre-offer conference	Friday, October 21, 2011
Eligibility Documents due	Friday, January 06, 2012
Issue Respondents' eligibility status	Friday, January 13, 2012
Deadline for receipt of Respondents' questions	Friday, January 13, 2012
Proposal Due Date Friday,	January 20, 2012
Commission hearing	Tuesday, January 31, 2012
Initial Shortlist evaluation complete	Friday, February 24, 2012
Notification of Selection to Initial Shortlist	Monday, February 27, 2012
Notification of intent to offer into BRA due to PJM	Thursday, March 01, 2012

Final Shortlist evaluation complete	Friday, March 30, 2012
Commission selects and approves any winning offers	Friday, April 06, 2012
EDC(s) execute Commission-approved agreements	Friday, April 13, 2012
Executed System Impact Study Agreement with PJM	Friday, April 13, 2012

9 RESERVED RIGHTS

9.1 RESPONDENT ELIMINATION RIGHT

If, in the course of the RFP process, a Respondent is found to provide faulty information, misrepresent itself, or omit any pertinent information, the Commission reserves the right to eliminate such Respondent from the RFP process. The Commission also reserves the right to reject any proposal that does not comport with the requirements set forth in the RFP.

9.2 CONTRACT TERMINATION RIGHT

If a Respondent who engages in any conduct described in Section 9.1 (Respondent Elimination Right) is awarded an offer and executes the contract, the Commission reserves the right to terminate the contract and pursue remedies as outlined in the Agreement.

9.3 WITHDRAWAL AND REJECTION RIGHT

The Commission reserves the right to order the EDCs to withdraw, modify, or cancel this RFP at any

time and the Commission may accept or reject any or all proposals received as a result of this RFP.

To the extent practicable, the Commission will inform Respondents that have filed an Expression of Interest form of any such change. The Commission further reserves the right to waive, in its sole discretion, any irregularity or defect in proposals received.

Nothing in this RFP limits the Commission's authority, and the Commission expressly reserves its authority to reject all submissions received under this RFP.

10 MISCELLANEOUS

10.1 WARRANTY ON INFORMATION

The information provided in the RFP has been prepared to assist Respondents in evaluating the RFP. It does not purport to contain all the information that may be, relevant to a Respondent in satisfying its due diligence efforts. The Commission makes no representation or warranty, express or implied, as to the accuracy or completeness of the information in the RFP, and shall not be liable for any representation expressed or implied in the RFP or any omissions from the RFP, or any information provided to a' Respondent by any other source.

Neither the RFP nor any other related correspondence from the Commission or its employees, agents, or consultants shall be considered legal, financial or other advice and does not establish a contract or any contractual obligations.

10.2 HOLD HARMLESS

Respondents shall hold the Commission and its employees, agents and consultants harmless of and

from all damages and costs, including but not limited to legal costs, in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a offer pursuant to this RFP.

Each Respondent is responsible for its costs incurred in responding to this RFP.

10.3 PROPOSALS BECOME COMMISSION PROPERTY

All proposals submitted by each Respondent pursuant to this RFP shall become the exclusive property of the Commission and will remain subject to the Confidentiality/Non-disclosure Agreement as set forth in Attachment 9.

10.4 RESPONDENT'S ACCEPTANCE

The submission of a proposal to the Commission shall constitute a Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of this RFP and the Agreement(s) that are a result of this RFP.

The Respondent and its representatives irrevocably agree to submit to the personal jurisdiction of any State or Federal court located in the State of Maryland and any appellate court thereof in respect of any action, dispute or proceeding arising out of this RFP process, including but not limited to the execution, implementation and performance of an Agreement.

10.5 PERMITS, LICENSES AND COMPLIANCE WITH THE LAW

Respondent shall obtain all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to respond to this RFP. Subcontractors, employees,

agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

10.6 REGULATORY APPROVALS

As indicated in Section 8 (Schedule for RFP Process) and as set out in the Agreement, the executed Agreement will be contingent upon the EDC's receipt of Commission approval. Respondent agrees to cooperate, to the fullest extent necessary, to obtain any and all required State, Federal or other regulatory approvals of the Agreement(s) resulting from its proposal(s).

10.7 NON-DISCRIMINATION POLICY

Throughout the RFP evaluation, the Commission will not discriminate between, or grant preferences to, any Respondent based on race, gender, ethnic origin, creed or religion, in accordance with legal requirements. The Commission's consideration, evaluation and selection of proposals shall be entirely based on the merits of each proposal and not upon unrelated factors.

ATTACHMENT 1

Contract for Differences Settlement Example for Illustrative Purposes Only

	Delivery Month		
	A	B	C
UCAP Offered, MW	500	500	500
Days in Month	30	31	30
Contract Prices			
Capacity, $/MWUCAP-day			
Firm fixed component	$270.00	$270.00	$270.00
Indexed Fixed O&M (FOM) component	$20.00	$21.00	$22.00
Total Contract Price	$290.00	$291.00	$292.00
Energy			
Indexed Variable O&M (VOM) $/MWh	$2.00	$2.05	$2.10
Heat rate, MMBtu/MWh	7	7	7
Gas Index Price, $/MMBtu (1)	$6.00	$7.00	$8.00
Strike Price, $MWh (2)	$44.00	$51.05	$58.10
Market Conditions			
RPM Capacity Price, $MWUCAP-day	$180.00	$190.00	$200.00

Energy dispatched MWh	216,000	167,400	126,000
Average Energy Price, $/MWh (3)	$55.00	$56.00	$57.00
Supplier Market Revenue			
RPM (4)	$2,700,000	$2,945,000	$3,000,000
Mkt Energy (5)	$11,880,000	$9,374,400	$7,182,000
Total	$14,580,000	$12,319,400	$10,182,000
Contract Payment Stream			
Capacity (6)	$4,350,000	$4,510,500	$4,380,000
Energy (7)	$9,504,000	$8,545,770	$7,320,600
Total	$13,854,000	$13,056,270	$11,700,600
CfD Monthly Net Payment			
Payment from Supplier to Buyer	$726,000	$0	$0
Payment from Buyer to Supplier	$0	$736,870	$1,518,600

(1) Average of daily Gas Price Index

(2) Strike Price=Indexed VOM + [Heat Rate * Gas Index Price]

(3) Sum of hourly market energy revenue divided by total energy dispatched

(4) RPM Revenue = RPM Price * UCAP Offered * Days in Month

(5) Market Energy Revenue = Sum of (Energy dispatched * Hourly Energy Price)

(6) Contract Capacity Payment = Contract Price * UCAP Offered * Days in Month

(7) Contract Energy Payment = Sum of (Energy Dispatched * Strike Price)

ATTACHMENT 2

CREDIT REQUIREMENTS

Credit and security requirements of this procurement are designed to protect the interests of ratepayers, while keeping the costs of compliance at a reasonable level. Requirements fall into three categories: Minimum Threshold Requirements, Completion Security, and Plant Performance Security. Principles for each category are discussed below.

1. Minimum Threshold Requirements

As indicated in Section 6.1, each proposal must provide financial information regarding the Respondent and, if applicable, Guarantor. Information required includes a financial plan for the unit detailing how the bidder will fund construction of the unit and how they will provide for the credit requirements in the contract-for-differences as well as two most recent years of audited financial statements and current senior unsecured long term debt credit ratings from Standard & Poor's, Moody's, and Fitch, if available. The Buyer will evaluate information provided and determine whether the Respondent has demonstrated adequate financial strength to perform as proposed. At the same time that the Proposal is due, bidders will be required to provide a letter of intent to provide credit security within 30 days of being selected to the final shortlist.

2. Completion Security

Selected Respondents (Suppliers) are required to post Completion Security collateral in the amount of $100 per kW of expected UCAP (approximately $95 per kW of installed capacity for dispatchable resources). The form of this collateral must be as

described in (4) below. This security is intended to cover the Buyer's opportunity costs should the Supplier's project not be completed.

3. Plant Performance Security

Suppliers must post Plant Performance Security in an initial amount of $50 per kW of Confirmed Contract Capacity (UCAP) effective on the Commercial Operation Date. The amount of this Security shall be reduced in each subsequent contract year in proportion to the remaining years of the Agreement term. For example, the amount in year 1 of a 20-year Agreement for 200 MW of installed capacity shall be $10,000,000. In the second contract year, the Security amount would be $9,500,000 or $10,000,000 * (19 / 20).

For fixed price fuel offers only, at the beginning of each Contract Year, the simple average of the Henry Hub Spot Price over the previous Contract Year will be compared to the fixed fuel price offered for the previous Contract Year. If the average Henry Hub Spot Price is 125% or greater than the fixed fuel price, the Buyer retains the right to request additional Completion and Performance Security. The amount of the additional Completion and Performance Security will be up to $50 per kW The additional Completion and Performance Security will be returned to the Supplier a) when the term of the fixed fuel price offer has expired, or b) when the annual comparison is performed and the average Henry Hub Spot Price is less than 125% of the fixed fuel price.

4. Forms of Completion Security and Plant Performance Security

The Completion Security and Plant Performance Security shall be provided in the form or either (i) cash, which will be held in an interest-bearing Escrow

account by a Qualified Institution selected by the Buyer for the benefit of the Buyer; (ii) a Letter of Credit; (iii) a. performance bond; (iv) a certified check made payable to the Buyer; (v) a bank .draft made payable to the Buyer; or (vi) other equivalent form of security acceptable to the Buyer acting reasonably, and subject to approval of the Commission. hut for certainty, shall not include guarantees. The Completion Security and Plant Performance Security also may be composed of a combination of such instruments so long as the total amount required above is achieved.

ATTACHMENT 3

Expression of Interest Form

To:
[Contact Name]
Maryland Public Service Commission

This response is an indication of our interest in the Request for Proposals for Generation Capacity Resources Under Long-Term Contract

Company*:_____

Contact Name*:_____

Contact Title*:_____

Address*:_____

City*:_____

State*:_____

Zip*:_____

Phone Number*:_____

Fax Number*:_____

E-mail Address*:_____

**Note: completion of all fields is required*

ATTACHMENT 4

Participation in Any Prior PJM Capacity Auction—Certification Form

I,_____("Agent") am an authorized signatory for _____("Respondent") and hereby certify that Respondent's Generation Resources committed as a result of this RFP were not cleared in any prior PJM capacity auction.

Signed:_____ Date:_____

Type or Print Name:_____

Title:_____

Company:_____

ATTACHMENT 5

PJM Membership and Certification Form

I_____("Agent") am an authorized signatory for_____("Respondent") and hereby certify:

Respondent is a member in good standing of the Pennsylvania-New Jersey-Maryland Interconnection, LLC ("PJM") and is able to comply with all applicable requirements of PJM to fulfill the obligations of this RFP, including performance under the Agreement provided as Attachment 8.

Signed:_____ Date:_____

Type or Print Name:_____

Title:_____

Company:_____

Respondent is not presently a member of PJM, however upon the award of a contract by the Commission for Generation Capacity Resources, Respondent will become a member of PJM and has the capability to meet all applicable membership requirements of PJM to fulfill the obligations of this RFP, including performance under the Agreement provided as Attachment 8.

Signed:Date:

ATTACHMENT 6

Binding Offer Agreement

_____("Respondent") agrees to be bound by the price and volume quotes contained in Respondent's proposal, up to the expiration time of its proposal, as set forth in Section 6.4 (Expiration of Proposals) of the Request For Proposals For Generation Capacity Resources Under Long-Term Contract dated [TBD] submitted to [EDC name] in response to the RFP, which shall constitute a firm offer to provide Generation Capacity Resources in accordance with the Agreement and applicable Maryland law and regulations. The Respondent agrees to execute the Agreement in a timely manner, as set forth in Section 8 (Schedule for RFP Process) of the RFP, for any proposal of the Respondent accepted by the Commission.

The submission of any binding offer to [utility name] shall constitute the Respondent's acknowledgment and acceptance of all the terms, conditions and requirements of the RFP.

The undersigned represents and warrants that he/she has the authority to act on behalf of, and to bind, the Respondent to perform the terms and conditions and otherwise comply with all obligations stated herein.

Signature: _____

Title:_____ Date_____

[ATTACHMENT 7 OMITTED]

ATTACHMENT 8

AGREEMENT
FIXED/INDEXED PRICING
CONTRACT FOR DIFFERENCES

WITNESSETH:

WHEREAS, pursuant to Section 7-510(c)(4)(ii)1.B, 7-510(c)(4)(ii)2.A and 7-510(c)(6) (collectively, parts of the "Customer Choice Act") of the Maryland Public Utility Article, Annotated Code of Maryland ("PUA"), the Maryland Public Service Commission (MDPSC) may require or allow an investor-owned electric company ("IOU") to procure electricity through bilateral contracts, as part of a portfolio of blended wholesale supply contracts of short, medium or long terms, and other appropriate electricity products and strategies, as needed to meet demand in a cost-effective manner and to construct, acquire or lease, and operate its own generating facilities to meet long-term anticipated demand in the State; and

WHEREAS, the Buyer issued a Request For Proposals ("RFP") to solicit offers to procure electricity through bilateral contracts for the construction, acquisition or lease and operation of generating facilities to meet long-term demand; and

WHEREAS, the MDPSC carefully evaluated the responses to the RFP, including the response submitted by the Supplier, and concluded that the Supplier is a qualified Respondent pursuant to the RFP, and that Supplier's offer to supply_____ MW of Capacity ("Original Contract Quantity") and Energy from the Facility pursuant to the terms of this Agreement meets the standards for selection in the RFP;

WHEREAS, the Buyer and Supplier wish to execute this Agreement in order to formalize their contractual arrangements on the terms and conditions set out herein;

WHEREAS, the Supplier will develop and operate the Facility to supply Capacity, Energy, Ancillary Services and other products from the Facility into the PJM Markets;

WHEREAS, the Buyer acknowledges that all payments it receives from the Supplier as a result of this Agreement, including any liquidated damages and/or Early Termination Payment, are for the benefit of Maryland ratepayers and should be credited back to Maryland ratepayers;

NOW, THEREFORE, in consideration of the promises and of the mutual agreements herein contained, the Parties to this Agreement covenant and agree as follows:

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ARTICLE 1

GENERAL DEFINITIONS

Initially capitalized terms used but not defined in this Agreement shall have the meanings set forth in the PJM Agreements or PJM Tariff (defined below). References to a given Article, Section, Subsection, or Exhibit are in reference to Articles, Sections, Subsections, or Exhibits in this Agreement, unless otherwise specified. The terms "hereof", "herein", "hereto", and "hereunder" refer to this Agreement as a whole. As used herein, the following terms shall have the following meanings:

"Actual Availability" means the ratio of Available Hours to Period Hours as reported by the Supplier to PJM based on the data in the GADS maintained by NERC or its successor, as applied in Section 3.4(c) of this Agreement.

"Additional Ratepayer Funding" has the meaning set forth in Section 3.3 in this Agreement.

"Adjustment Ratio" has the meaning set forth in Section 6.2(b) of this Agreement. "Ancillary Services" has the meaning ascribed thereto in the PJM Agreements.

"Availability" means the capability of a resource, in whole or in part, at any given time, to produce and supply Energy or Capacity located within the Southwest MAAC Locational Deliverability Area in accordance with accepted electric industry practice, and "Available" shall mean that a resource is capable, in whole or in part, at a given time, to produce and supply Energy or Capacity, dispatchable from, within the Southwest MAAC Locational Deliverability Area in accordance with such accepted electric industry

practice standard. Period availability expressed as a percentage shall be equal to the Available Hours divided by Period Hours as set forth herein.

"Availability Deficiency" shall have the meaning set forth in Section 3.1(f)(4) of this Agreement.

"Available Hours" shall have the meaning set forth in the GADS Data Instructions Version 01/2006 Section IV-D "Unit Time" or its successor.

"Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it (unless such receivership is dismissed or stayed within thirty (30) calendar days), (ii) makes an assignment or any general arrangement for the benefit of creditors other than collateral assignments or other security instruments in favor of a Financing Party, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

"Bankruptcy" means a proceeding under the Bankruptcy Code.

"Bankruptcy Code" means those laws of the United States of America related to bankruptcy codified and enacted as Title 11 of the United States Code, entitled "Bankruptcy" and found at 11 ,U.S.C. § 101 et seq., as such laws may be amended, modified, replaced or superseded from time to time.

"BRA" means the Base Residual Auction in PJM's RPM or any successor to the RPM.

"Business Day" means any day except a Saturday, Sunday or a day that PJM declares to be a holiday, as posted on the PJM website. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. Eastern Prevailing Time ("EPT").

"Buyer" means an electric company regulated by the MDPSC and the Party serving as the counterparty to the Supplier in this Agreement.

"Capacity" means the continuous load carrying capability of the generating Facility at a given time; this will be defined consistent with the PJM Agreements, as amended from time to time.

"Capacity Clearing Price" means the resource clearing price in the BRA for an applicable Delivery Year or any successor auction or equivalent market if an auction is no longer utilized.

"Capability Testing" means the PJM testing of capacity resources to assess the seasonal claimed capability of each resource pursuant to PJM's rules and Procedures for Determination of Generating Capability, or as specified in PJM Agreements, as it may be amended from time to time.

"Claiming Party" means the Party claiming relief from liability or obligations hereunder as the result of a Force Majeure event or circumstance.

"Code of Conduct" has the meaning defined in Exhibit to this Agreement.

"Commercial Operation" means a status under which the Facility has officially started commercial operations, and meets all of the requirements set out in Section 2.6 of this Agreement.

"Commercial Operation Date" means the date on which the Facility is supposed to attain Commercial Operation, as set forth in Exhibit B to this Agreement.

"Completion and Performance Security" has the meaning set forth in Section 10.1 of this Agreement.

"Confirmed Contract Quantity" means the quantity of Capacity in MW terms that the Supplier has offered to supply into the BRA and that the Parties will be settling against under this Agreement, as confirmed at the Facility's Commercial Operation Date.

"Contract Annual Heat Rate" means the amount of energy in BTUs consumed by the Units to produce a kWh of energy as specified in the Supplier's Proposal and listed in Exhibit C.

"Contract Summer Qualified Capacity" means the benchmark measure of capacity established in accordance with Section 2.6(e) of this Agreement.

"Contract Target Availability" means the percentage Availability (for a particular Contract Year) that the Supplier has committed under the terms of this Agreement to maintaining the Facility over the period of a given Contract Year, reflecting adjustments for forced outages and planned maintenance, as stated in Exhibit C to this Agreement.

"Contract Year" means a twelve (12) month period during the Term which begins on the Term Commencement Date or the anniversary date thereof.

"Credit Rating" means the rating assigned to a Party's or Qualified Institution's unsecured senior long-term debt obligations (not supported by third party credit enhancements) or if a Party does not have a rating for its senior unsecured long-term debt, then one rating notch below the rating then assigned to the

Party as an issuer and/or corporate credit rating by S&P, Moody's, or Fitch. if there are split ratings, the lowest of the Credit Ratings will apply.

"Customer Choice Act" has the meaning set forth in the preamble to this Agreement.

"Day-Ahead Energy Market" means the hourly day-ahead energy market currently operated by PJM, or any successor market thereto.

"Day Ahead Locational Marginal Price" means the hourly energy market clearing price in the PJM Day-Ahead Energy Market at a specified location.

"Defaulting Party" has the meaning set forth in Section 8.6 of this Agreement.

"Delist" means removed from PJM Capacity Resource status, as provided in Appendix DD of PJM's Open Access Transmission Tariff, Section 5.6.6(d).

"Deliverable" means that the Facility is electrically interconnected to the PJM System and that the electrical output of the Facility is anticipated to flow to the benefit of Maryland load during transmission network peak loading conditions, as analyzed by PJM, or a competent third party acceptable to the MDPSC.

"Delivery Year" means the PJM Planning Period for which a Capacity Resource is committed pursuant to the RPM auction procedures.

"Disclosing Party" has the meaning set forth in Section 12.10 of this Agreement. "Dispatchable" has the meaning set forth in the PJM Agreements.

"Early Termination Date" has the meaning set forth in Section 8.6 of this Agreement. "Early Termination Payment" has the meaning set forth in Section 8.7 of

this Agreement. "EDC" means an Electric Distribution Company.

"Effective Date" has the meaning set forth in Section 5 of this Agreement.

"Energy" means a three-phase, 60-cycle alternating current electric energy, expressed in units of kilowatt-hours or megawatt-hours.

"EPC Contractor" means the Engineering, Procurement, and Construction Contractor responsible for designing and building the Facility.

"Escrow" means a deposit account held in a Qualified Institution bearing interest equal to 200 basis points (2%) above a Qualified Institution's prime rate.

"Event of Default" has the meaning set forth in Article 8 of this Agreement.

"Execution Date" means the later of (i) the date on which both Parties execute this Agreement or (ii) the date on which the second of the Parties executes this Agreement in the event that both Parties were unable to execute the Agreement on the same date, as set forth in the preamble to this Agreement.

"Export Offer" has the meaning that is defined in the PJM Tariff and Agreements.

"Facility" means as all land, rights of way, Units and related equipment and facilities of the electric generating plants to be or being constructed by the Supplier on site in connection with the Units. The Facility shall include, without limitation, the Units and all auxiliary equipment and facilities installed at the plant necessary or used for production, control, delivery or monitoring of electricity produced on the Site by such Units.

"Federal Power Act" means the Federal Power Act, 16 U.S.C. §§ 791 et seq, as amended from time to time.

"FERC" means the Federal Energy Regulatory Commission, or any successor thereto.

"Financial Participant" means the term used under the Bankruptcy Code, pursuant to 11 U.S.0 11 § 101 (22A), as it may be amended from time to time.

"Financing Parties" means the lending institutions (including any trustee or agent on behalf of such institutions) providing financing or refinancing, any other credit enhancement or interest rate hedging products to the Supplier for the acquisition, construction, ownership, operation, maintenance, or leasing of the Facility.

"Fitch" means Fitch Investor's Service, Inc., or its successor.

"Force Majeure" means an event or circumstance that (i) prevents one Party from performing its obligations under this Agreement; (ii) is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and, (iii) by the exercise of due diligence, the Claiming Party is unable to overcome or avoid, or cause to be avoided; provided, however, notwithstanding the foregoing, none of the following events or circumstances will constitute Force Majeure: (a) the loss or failure of Supplier's Fuel supply, except when caused by Force Majeure; (b) Supplier's ability to sell Capacity at a price greater than the price set out in Article 6; (c) the breakdown of Supplier's plant and/ or equipment, except when caused by Force Majeure; (d) an occurrence or an event that merely increases the costs of, or causes an economic hardship to, a Party; and (e) Buyer's ability to procure the

supply of Capacity at a price lower than that set forth in Article 6 to this Agreement.

"Fuel" means any fuel used to start or operate the generating Facility. The type of Fuel used by this Facility is specified in Exhibit C to this Agreement.

"GADS" means the Generating Availability Data System ("GADS"), which is managed by NERC and which collects, records, and retrieves operating information from generators.

"Government Authority" means any federal, state, local, territorial or municipal government body; any governmental, judicial, regulatory or administrative department, agency, commission, board, bureau, body, or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory, or taxing authority or power, including any independent system operator or any control area operator, or any court or governmental tribunal.

"Indemnified Party" has the meaning set forth in Section 12.8 of this Agreement. "Indemnifying Party" has the meaning set forth in Section 12.8 of this Agreement. "Initial Notice" has the meaning set forth in Section 12.9 of this Agreement.

"Interconnection Agreement" means the contracts that each new generation Facility must sign with PJM and/or with the entity that owns the transmission or distribution facilities with which such new Facility interconnects in order to interconnect to the PJM electricity network, as specified by PJM rules on interconnections and the PJM Agreements.

"Investment Grade Rating" means a Credit Rating of " Baa3" or better from Moody's, and "BBB-" or better from S&P or Fitch. If there are split ratings, the lowest of the Credit Ratings will apply.

"IOU" means an investor-owned Electric Company.

"Key Milestone Event" means the Milestone Events that are starred with an asterisk in Exhibit B to this Agreement.

"kW" means a kilowatt or kilowatts.

"Law" or "Laws" means all laws, rules, regulations, codes, injunctions, judgments, orders, decrees, rulings, interpretations, constitutions, ordinances, common law, or treaty, of a Government Authority.

"Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank. Requirements for qualified Letters of Credit under this Agreement are described in Article 10 of this Agreement.

"Market Based Rate Authorization" means the FERC process authorized pursuant to Section 205 of the Federal Power Act granting generators the right to sell Energy, Capacity, and/or Ancillary Services at market based rates.

"Market Change" means any change in the PJM Tariff, as well as any other significant and material change to the Tariff or the operation of the PJM Markets.

"MDPSC" means the Maryland Public Service Commission, or any successor thereto.

"Milestone Date" means the date by which a specific Milestone Event shall be completed, as laid out in Exhibit B to this Agreement.

"Milestone Event" means the end of each phase of Facility development, culminating in the Facility's Commercial Operation. Milestone Events under this Agreement are provided in Exhibit B to this Agreement.

"Monthly Payment Amount" has the meaning set forth in Exhibit F hereto. "Moody's" means Moody's Investors Service or its successor.

"MW" means a megawatt or megawatts.

"New Entry" has the meaning set forth in the PJM Tariff and PJM Agreements.

"Non-Claiming Party" means the counterparty under this Agreement to the Claiming Party.

"Non-Defaulting Party" has the meaning set forth in Section 8.6 of this Agreement. "Non-Disclosing Party" has the meaning set forth in Section 12.10 of this Agreement. "Non-Paying Party" has the meaning set forth in Section 6.5(c) of this Agreement.

"North American Electric Reliability Council" or "NERC" means the North American Electric Reliability Council or any successor organization there to.

"Off-peak Day-Ahead Locational Marginal Price" means hourly energy market clearing prices during off-peak hours in the PJM Day-Ahead Energy Market at a specified location, as defined by PJM.

"On-peak Day-Ahead Locational Marginal Price" means hourly energy market clearing prices during

on-peak hours in the PJM Day-Ahead Energy Market at a specified location, as defined by PJM.

"Original Contract Quantity" means the RPM Contract Quantity that was specified in the Supplier's Proposal and was listed in Exhibit C at the Execution Date, as may be adjusted pursuant to Section 2.5(d) of this Agreement.

"Parties" means collectively both the Supplier and the Buyer. "Party" means either the Supplier or the Buyer.

"Paying Party" has the meaning set forth in Section 6.5(c) of this Agreement.

"Period Hours" means all hours in a specified period of time.

"Permits" means all siting, environmental, and local municipal permits and/or approvals that must be obtained in order for a generation Facility to begin or continue operations in the state of Maryland.

"Person" means a natural person, firm, trust, partnership, limited partnership, limited liability company, or corporation (with or without share capital), joint venture, sole proprietorship, governmental entity, or other entity of any kind.

"PJM" means the PJM Interconnection, L.L.C. or any successor organization thereto.

"PJM Agreements" means the PJM Operating Agreement, PJM Reliability Assurance Agreement, PJM West Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding or amended versions that may take effect from time to time.

"PJM Markets" means all markets currently operated by PJM, and any successor markets thereto, and any additional markets that may be developed by PJM in the future.

"PJM Planning Period" has the meaning set forth in the PJM Agreements. Currently, the PJM Planning Period is the twelve months beginning June 1 and extending through May 31 of the following year.

"PJM System" or "System" means the electricity network and wholesale market operated by PJM.

"Point of Interconnection" means the point on the electricity network at which the Facility interconnects to the electricity network, and is listed in Exhibit A of this Agreement.

"Proposal" means the proposal submitted by the Supplier to the MDPSC under the Buyer's competitive solicitation process to encourage the development of new Capacity in the state of Maryland which resulted in this Agreement.

"Prudent Utility Practice" means the practices, methods, and acts recognized as good engineering practices applicable to the design, building, and operation of electric generating facilities of similar type, size and capacity, and that at a particular time, in the exercise of reasonable judgment in light of the facts known or that shall reasonably have been known at the time a decision was made, will have been expected to accomplish the desired result in a manner consistent with applicable Law, Permits, equipment manufacturer's recommendations, reliability, safety, environmental protection, and the Supplier's obligations under this Agreement. With respect to the Facility, Prudent Utility Practice includes (but is not limited to) taking reasonable steps to ensure that:

1. equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

2. sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly (taking into account manufacturers' guidelines and specifications as well as interconnected electric system status), efficiently, and in coordination with the Buyer and PJM and are capable of responding to emergencies as well as normal conditions;

3. preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

4. appropriate monitoring and testing are performed to ensure equipment is functioning as designed and will be expected to function properly during normal, abnormal and emergency conditions;

5. equipment is not operated in a reckless manner, in violation of manufacturer's guidelines or in a manner unsafe to workers, the general public, the interconnected system, or contrary to Laws or Permits or without regard to defined limitations such as flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, synchronization, and/ or control system limits; and

6. equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function as designed over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site and under both normal conditions and conditions involving an emergency.

"Qualified Institution" means a commercial bank or trust company with (i) a Credit Rating of at least (a) "A" by S&P and "A2" by Moody's, if such entity is rated by both S&P and Moody's or (b) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both, and (ii) having a capital surplus of at least $10,000,000,000.

"Ramp Rate" means a Facility's capability to increase or decrease energy output after start-up, synchronization to the system, and technically required hold generation "set" points, for operation between minimum load and maximum continuous rating, as defined in PJM Agreements, as it may be amended from time to time.

"Reliability Must Run Contracts" or "RMRs" means cost-of-service contracts that are signed with generators by PJM for reliability purposes and approved by FERC.

"Reliability Pricing Model" "RPM" means the mechanism established in the PJM Tariff for pricing capacity.

"Renewable Attribute" means any renewable attribute that the Facility may possess, including but not limited to renewable energy credits and low emissions attributes.

"Replacement Price" means the price at which the Buyer, acting in a commercially reasonable manner, purchases or could have purchased Capacity or Energy, as the case may be, equal to the amount of Capacity or Energy, as the case may be, that were otherwise not provided by the Supplier in accordance with this Agreement, plus costs reasonably incurred by the Buyer in purchasing such replacement Capacity and Energy. Any applicable market prices, shall be deemed to be commercially reasonable prices for purposes of this definition.

"Representatives" has the meaning set forth in Section 12.10 of this Agreement.

"S&P" means Standard & Poor's Rating Group, a division of McGraw-Hill, Inc., and its successors.

"Settlement Amount" means the amount calculated in accordance with Section 8.7 of this Agreement.

"Site" means those parcels of real estate and rights of way on or by which the Facility is or will be located.

"Southwest MAAC" or "SWMAAC" means the Southwest Mid-Atlantic Area Council Locational Deliverability Area, as defined by PJM.

"Supplier" means a [legal form of Supplier], [incorporated/organized] under the laws of the State of Maryland, that pursuant to this Agreement is assuming the obligations of offering in a specified quantity of Capacity and Energy into the PJM Markets for the Term of this Agreement.

"Tariff" means the Open Access Transmission Tariff and market rules established by PJM for the operation of the PJM Markets, including but not limited to the Reliability Pricing Model, and the Day-Ahead Energy Market.

"Tax" or "Taxes" means all taxes that are currently or may in the future be assessed on any products or services that are the subject of this Agreement.

"Term" has the meaning set forth in Article 5 in this Agreement.

"Term Commencement Date" has the meaning defined in Article 5.2 of this Agreement.

"Term Termination Date" means the earlier of (i) the date on which this Agreement expires, which will be the day before the Term Commencement Date plus the number of years in the Term, or (ii) the date upon which a Party terminates this Agreement in accordance with the provisions of the Agreement.

"Unforced Capacity" or "UCAP" means the installed Capacity of the Facility rated at summer conditions that are not on average experiencing a forced outage or forced de-rating, as determined by PJM pursuant to the PJM Agreements and PJM Tariff.

"Unit(s)"means the physical unit(s) of the Facility supporting the Supplier's offer of Capacity or Energy pursuant to the terms of this Agreement.

ARTICLE 2

FACILITY DESCRIPTION AND SUPPLIER'S OBLIGATIONS DURING DEVELOPMENT AND CONSTRUCTION

2.1 Summary of Facility Development and Construction

(a) The Supplier shall construct, own, operate, and maintain the Facility, which shall consist of a [_insert prime mover/technology of facility], located in having an Original Contract Quantity of [ ] MW, the technology of which complies with

the eligibility criteria established by the RFP. Exhibit A provides a detailed description of the Facility, including identification of all the equipment and components.

(b) The Supplier shall at no time after the Execution Date of this Agreement modify, vary, or amend in any respect any of the features or specifications of the Facility described in Exhibit A, in particular any changes affecting the Facility's Original Contract Quantity, Contract Summer Qualified Capacity Availability, level of environmental emissions, or operating efficiency in such a way as will materially and adversely affect the Supplier's ability to perform its obligations under this Agreement, or which changes the economic balance of this Agreement, as defined by the anticipated payments relative to anticipated benefits under this Agreement for each Party as of the Execution Date, except as provided for in Section 2.1(d) of this Agreement.

(c) The Supplier may make immaterial changes to the Facility as long as such immaterial changes do not have an adverse impact on the Supplier's ability to fulfill its obligations under this Agreement. The Supplier must notify the Buyer of any such immaterial changes by providing written notice within thirty (30) calendar days of the immaterial change. The Buyer shall amend this Agreement as needed, send the amended Agreement to the Supplier, and file the amended Agreement with the MDPSC within thirty (30) calendar days of the date on which written notice was sent by the Supplier regarding such immaterial changes.

(d) If the Supplier seeks to change any features or specifications of the Facility in Exhibit A in a manner that is material, but which will not adversely affect the Supplier's ability to perform its obligations under this Agreement, the Supplier must submit written notification about such changes and their potential impact on Supplier performance to the Buyer for its review and recommendation approving, approving with modification or rejecting the proposed changes. Buyer shall submit its written recommendation to the MDPSC for its review and decision. If the MDPSC approves any proposed changes, the Supplier shall provide an amended Exhibit A to the Buyer and the MDPSC within five (5) Business Days.

2.2 Location

(a) The Facility shall be physically located entirely within the Southwest MAAC Locational Deliverability Area as defined by PJM and interconnected to the System such that the Facility's Original Contract Quantity shall be interconnected to a node within the Southwest MAAC Locational Deliverability Area as defined by PJM.

(b) The physical address of the Facility is [_____]. A scaled map that identifies the location of the Facility, the location of the Point of Interconnection, and the location of the important ancillary and interconnection facilities is included in Exhibit A.

2.3 General Design of Facility

The Supplier shall construct the Facility according to Prudent Utility Practice, meeting PJM's interconnection standards, the PJM Agreements, and all other applicable Laws and Permits. The Supplier shall ensure that the Facility is designed, engineered and constructed to operate in accordance with the requirements of this Agreement from the Effective Date until the end of the Term.

2.4 Interconnection

The Supplier shall assume responsibility for and bear all costs and expenses of the generator interconnection process for the Facility that are imposed in accordance with (i) the PJM Agreements, (ii) applicable Laws, including all the costs of any interconnection studies, and (iii) all other interconnection-related costs associated with, or triggered by, the Supplier's Facility. Consistent with the PJM Agreements, the Buyer shall cooperate with the Supplier and shall make reasonable efforts to ensure the timely negotiation and execution of the interconnection Agreement and timely completion of the Interconnection and any required system upgrades.

2.5 Milestones for Commercial Operation

The Supplier acknowledges that time is of the essence to the Buyer with respect to attaining Commercial Operation of the Facility by the corresponding Milestone Date set out in Exhibit B, and agrees:

(a) that each of the Milestone Events as described in Exhibit B to this Agreement shall be achieved in a timely manner and by its corresponding Milestone Date. The Supplier will provide written notice to the Buyer and the MDPSC substantiating and certifying the completion of

each Milestone Event (or, if not completed, providing a status report and expected completion date) no later than five (5) Business Days after the Milestone Date. The Supplier's failure to timely achieve a Milestone Event, except the Milestone Date for Commercial Operation as provided herein, shall not constitute an Event of Default.

(b) that, subject to Section 9.2(c), each of the "Key Milestone Events" (which are Milestone Events that are starred with an asterisk in Exhibit B to this Agreement) before Commercial Operation shall be achieved in a timely manner and by its corresponding Milestone Date, failing which the Supplier shall pay to the Buyer within five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money to be held in an escrow account equal to U.S. Dollars 5 per MW multiplied by the Original Contract Quantity (MW) for each calendar day after the applicable Milestone Date, until the corresponding Milestone Event has been achieved. However, if Commercial Operation is achieved on or before the Milestone Date for Commercial Operation listed in Exhibit B hereto, then all such liquidated damages for delays prior to Commercial Operation paid by the Supplier shall be refunded to the Supplier, plus any interest that has accrued on said amount while said amount was held in an Escrow account;

(c) that, subject to Section 9.2(c), Commercial Operation shall be achieved by the Milestone Date for Commercial Operation listed in Exhibit B hereto, failing which the Supplier

shall pay to the Buyer on or before five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money to be held in an escrow account equal to U.S. Dollars 150 per MW multiplied by the Original Contract Quantity (MW), for each calendar day after the anticipated Milestone Date for Commercial Operation listed in Exhibit B hereto until Commercial Operation has been achieved or until 90 calendar days has expired, as set forth in Section 8.1(d)1;

(d) that, using a methodology consistent with PJM's approach for verifying a resource's Unforced Capacity, the Supplier must demonstrate that the Facility's Unforced Capacity is equal to or more than the Original Contract Quantity (MW) at the date of Commercial Operation, or, in the case of a Facility that is already in operation, the Effective Date.

1. If the Facility's Unforced Capacity is equal to or exceeds the Original Contract Quantity, the Confirmed Contract Quantity shall equal the Original Contract Quantity.

2. The Supplier shall have thirty (30) calendar days to cure any deficiency in the Facility's Unforced Capacity, failing which the Supplier shall pay to the Buyer on or before five (5) Business Days after receipt of an invoice from the Buyer, as liquidated damages, a sum of money equal to U.S. Dollar 226 per kW multiplied by the deficiency between the Unforced Capacity and the Original Contract Quantity.

3. if the Supplier cannot demonstrate that the Unforced Capacity of the Facility is equal to or more than the Original Contract Quantity within this thirty (30) calendar day cure period, and provided that the Supplier has paid to the Buyer all of the liquidated damages required by this Subsection 2.5(d), the Confirmed Contract Quantity shall be set equal to the demonstrated Unforced Capacity. The Supplier will provide notice immediately to the MDPSC and the Buyer of the Confirmed Contract Quantity.

(e) that if this Agreement is terminated due to an Event of Default under Section 8.1(e), the Supplier shall pay to Buyer, in addition to liquidated damages provided in this Article 2 an Early Termination Payment pursuant to Section 8.7.

(f) that the damages set out in this Article 2 will not apply and the failure to achieve Commercial Operation by the Milestone Date for Commercial Operation shall not constitute an Event of Default, if the MDPSC determines that the delay is due to (i) a Force Majeure event; (ii) a material breach by the Buyer of its obligations under this Agreement, pursuant to Article 4; (iii) a delay in obtaining regulatory approval from any relevant Government Authority, which was not caused by the Supplier, by the Supplier's failure to perform a required task, or otherwise not the fault of the Supplier or its agent; or (iv) an appeal of the MDPSC Decision approving the executed contracts in Case No. 9214;

1. The Supplier will provide the Buyer and the MDPSC with written notification and supporting documentation of having obtained all required regulatory approvals within two (2) Business Days of the Milestone Date.

2. If the MDPSC determines that a delay is excused by Section 2.5(u) through (iv) above, a new Milestone Date for Commercial Operation shall be established that results in a day for day extension of the Milestone Date for Commercial Operation corresponding to the length of the delay created by (ii) through (iv) above. Any extension of time provided for a Force Majeure event shall be governed by Section 9.2.

(g) that each Party acknowledges and agrees with respect to the liquidated damages in this Article 2 that:

1. the actual damage expected as a result of the Supplier's breach of these requirements would be substantial;

2. both Parties intend that the Supplier would pay the specified liquidated damages amount for such a breach;

3. this amount of damages is not a penalty;

4. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer would sustain if the Supplier breaches this provision;

5. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and

6. such liquidated damages shall be the sole damages to which the Buyer shall be entitled as a result of the Supplier's breach of these requirements, except that the Buyer is entitled to assess an Early Termination Payment, if also applicable, to the Supplier's failure to achieve Commercial Operation.

2.6 Requirements for Commercial Operation

The Facility will be deemed to have achieved Commercial Operation at the point in time when all of the following occur:

(a) The Supplier (i) has completed its Interconnection Agreement with PJM and, if applicable, FERC has accepted the Interconnection Agreement and (ii) has provided the Buyer and MDPSC with copies of the Interconnection Agreement filed with FERC.

(b) The interconnection of the Facility to the PJM System has been completed in accordance with the Interconnection Agreement, and Supplier has provided Buyer and the MDPSC with a true copy of- written confirmation from PJM confirming that interconnection service is available at the Point of Interconnection.

(c) The Buyer has received a certificate addressed to it from an independent professional engineer, knowledgeable in power facility construction and duly qualified to practice engineering in Maryland. The Supplier's EPC Contractor can serve as an independent engineer as long as the EPC Contractor is not the Supplier, subject to the Buyer's approval. The certificate shall be procured at the expense of the Supplier, and shall state that:

1. the Facility has been completed in all material respects excepting punch list items that do not materially and adversely affect the ability of the Supplier to operate the Facility in accordance with, and perform its obligations under, the provisions of this Agreement; and

2. the Facility in its current form is capable of operating reliably as a part of the PJM interconnected system, and that the Facility is able to perform according to the terms described in Exhibit C to this Agreement.

(d) The Supplier commits to participating in the BRA, the Day-Ahead Energy Market, Ancillary Services Market or other markets as determined by the MDPSC in accordance with Section 3.2 of this Agreement, that the Facility meets all requirements in the PJM Agreements for BRA, the Day-Ahead Energy Market, Ancillary Services Market or other markets, as laid out in the applicable PJM Agreements, as they may be amended from time to time.

(e) The Supplier has certified that the Facility is ready to begin Commercial Operation and has provided the documentation to the Buyer and the MDPSC resulting from the Facility's operational test, and any other relevant documentation from PJM allowing it to begin Commercial Operation of the Facility, including but not limited to PJM's Procedures For Establishing The Capability Of Generation Capacity Resources (Schedule 9 to the Reliability Assurance Agreement or any successor provision) and PJM's Procedures For Establishing Deliverability Of Generation Capacity

Resources (Schedule 10 to the Reliability Assurance Agreement or any successor provision) for the purpose of determining the Facility's Unforced Capacity. Based on the results of this operational test, the Contract Summer Qualified Capacity shall be set equal to the Facility's Unforced Capacity.

(f) The Supplier has obtained and submitted to the Buyer certificates of insurance evidencing the coverage required by Section 2.8 of this Agreement.

(g) A duly authorized officer of the Supplier familiar with the Facility must submit to the Buyer and the MDPSC an affidavit stating that all Permits to construct and/or operate the Facility have been obtained in compliance with applicable Law and this Agreement by the Supplier (at the Supplier's sole cost and expense) and are in full force and effect, and that Supplier is in compliance with the terms and conditions of this Agreement and said Permits in all material respects.

(h) The Supplier must provide documentation to the MDPSC and the Buyer demonstrating (i) that it has the required Permits to burn its primary and secondary fuels and (ii) its secondary fuel requirement is met by consuming liquid fuel stored on site, that it has adequate on-site storage for such liquid fuel and/or contracts to refill on-site storage when the liquid fuel is spent sufficient to operate the Facility for at least 24 consecutive hours using the secondary fuel. The Supplier must update this documentation annually, as specified in Section 3.2(a) of this Agreement.

2.7 Progress Reports During Design and Construction; Buyer's Ability to View and Confirm Supplier Tests and Milestones

(a) By the fifteenth (15th) day of each January, April, July, and October of each Contract Year following the Effective Date of this Agreement and continuing until the Commercial Operation Date, the Supplier shall provide the Buyer and the MDPSC with quarterly progress reports in a form agreed to by the Parties describing the status of efforts made by the Supplier to meet each Milestone Date and the progress of the design and construction work. At the MDPSC's or the Buyer's request, the Supplier shall provide an opportunity for the Buyer to meet with appropriate personnel of the Supplier to discuss and assess the contents of any such quarterly progress report.

(b) With respect to each Milestone Event and test that this Agreement requires the Supplier to complete, the Buyer, the MDPSC, and their designated agents shall have (i) the right (but not the obligation) to obtain access to the Site, the Facility, and relevant Supplier records (accompanied by an employee or representative of the Supplier) to confirm that each such Milestone Event has been achieved and/ or that each Milestone Event complies with the applicable requirements of this Agreement, and (ii) the right to receive prior notice of, and an opportunity to view, each test the Supplier is required to perform pursuant to this Agreement.

2.8 Insurance Covenants

(a) The Supplier hereby agrees to put in effect and maintain, or cause its contractors and subcontractors, where appropriate, to maintain from the commencement of construction of the Facility to the end of the Term, at its own cost and expense, with insurers reasonably acceptable to the Buyer and authorized to underwrite insurance in Maryland, all the necessary and appropriate insurance that a prudent Person in the business of the Supplier (developing, constructing, and operating an electric generating facility) will maintain, including the following:

1. "all-risk" property insurance covering property of every description, in the joint names of at least the Supplier and its principal contractors, insuring not less than the full replacement value of the Facility. During the construction of the Facility until the Commercial Operation Date, the policy shall include as additional insured all subcontractors, as their respective interests may appear.

2. boiler and machinery insurance, if applicable, in protecting the interest of the Supplier and its principal contractors, and anyone having an ownership interest in the property in question, as their respective interests may appear, insuring not less than the full replacement value of the boilers, machinery, pressure vessels, service supply objects and other insurable objects forming part of the Facility.

3. commercial general liability insurance covering death, bodily injury and property damage and other types of damage that may be caused to third parties as a result of the Supplier's activities in connection with the Facility or performance of its obligations under this Agreement, and

4. environmental/pollution liability insurance, providing coverage for any third party claims for bodily injury, property damage and clean-up for pollution and environmental incidents arising out of the construction, operation or maintenance of the Facility.

(b) The Supplier shall provide the Buyer with proof of the insurance required in this Section 2.8 in the form of valid certificates of insurance that reference this Agreement and confirm the required coverage, on or before the commencement of construction of the Facility, and renewal or replacements on or before the expiration of any such insurance. Buyer shall be named as an "additional insured" party on the insurance policy. Each such certificate of insurance shall require the insurance carrier and/or insurance broker to provide the Buyer with thirty (30) calendar day's prior notice in the event of any material change, cancellation, or failure to renew the insurance coverage required by this Section 2.8. The Supplier's failure to maintain coverage identified in (1) through (4) of Section 2.8(a) shall be an Event of Default pursuant to Section 8.1(c).

ARTICLE 3

SUPPLIER'S OBLIGATIONS AFTER COMMERCIAL OPERATION OF THE FACILITY

3.1 Operations and Performance Requirements

(a) During Commercial Operation, the Supplier shall agree to operate and maintain the Facility according to Prudent Utility Practice, consistent with PJM's interconnection standards, and in accordance with the Interconnection Agreement, all Permits and requirements of Law applicable to the Facility.

(b) At all times during Commercial Operation, the Supplier shall be responsible for all performance requirements mandated by the PJM Tariff and PJM Agreements, including performance requirements (and payment of penalties, if any) associated with the PJM Markets, and successors thereto, that the Supplier is contractually obligated to participate in (pursuant to Section 3.1(a) and 3.1(b) of this Agreement).

(c) The Supplier may not recover amounts or any penalty payments or payment deductions incurred by the Supplier resulting from the Supplier's failure to meet PJM Tariff performance requirements if said failure to meet the performance requirement is not excused by Force Majeure, unless the MDPSC has approved any such cost recovery.

(d) The Supplier does not bear the risk of changes to the PJM transmission system that are beyond Supplier's control and which may result in energy from the Facility not being Deliverable as specified in Section 2.2(a).

(e) The Supplier must not undertake any actions (other than actions that are reasonably required in accordance with Prudent Utility Practice), Or neglect to perform any reasonably required actions, with respect to the Facility such that Energy from any portion of its UCAP represented in Exhibit A is not Deliverable in the state of Maryland over the Term of this Agreement.

(f) The Supplier must maintain its warranted Contract Target Availability for the Facility throughout the Term of the Agreement.

1. The Supplier must provide to the Buyer and the MDPSC a copy of the GADS data on the same day that the Supplier is required to provide the data to PJM.

2. The Facility must maintain the level of Contract Target Availability for the given Contract Year.

3. The Buyer will assess the Facility's Actual Availability on a rolling annual average for a two-year period basis based on the GADS data provided to the Buyer and the MDPSC by the Supplier by dividing the number of hours in the previous two Contract Years that the Facility was Available (Available Hours) by the total number of hours in the previous two Contract Years (Period Hours), excluding hours where performance was prevented due to Force Majeure. For the first year of Commercial Operation, Actual Availability will be assessed using only that first year of data. If the Supplier's Actual Availability on average over the previous

Contract Year is more than 5% below the Contract Target Availability for that Contract Year and warranted by the Supplier in the annual Contract Target Availability schedule listed in Exhibit C, the Supplier will pay liquidated damages to the Buyer, according to Section 3.1(0(4) below. If the Supplier's Actual Availability on average over the previous Contract Year is more than 5 % above the Contract Target Availability for that Contract Year and warranted by the Supplier in the annual Contract Target Availability schedule listed in Exhibit C, the Buyer will pay the Supplier an Availability Bonus, according to 3.1(0(5) below.

4. The Availability Deficiency will be calculated as shown in the formula below (in this Section 3.1(0(4). Note that these damages are independent from any other liquidated damages or penalties that the Supplier may pay to PJM for availability or performance issues, which are used to adjust the Monthly Payment Amount pursuant to Section 6.2 of this Agreement.

   i. Availability Deficiency = Actual Availability - (Contract Target Availability - 5%)

   ii. If the Availability Deficiency is less than zero, the Supplier must pay the Buyer liquidated damages equal to the product of (i) the weighted average of (A) the annual average On-peak Day-Ahead Locational Marginal Price and (B) the annual average Off-peak Day-Ahead Locational Marginal Price (calculated

using the weighted average of On-peak and Off-peak hours for the node from which the Facility is dispatchable for the relevant two-year period), (ii) the Availability Deficiency expressed as a percentage, (iii) Confirmed Contract Quantity, and (iv) the number of Period Hours in previous Contract Year.

5. The Availability Bonus will be calculated as shown in the formula below (in this Section 3.1(f)5).

   i. Availability Bonus = (Contract Target Availability + 5%) ¬Actual Availability

   ii. If the Availability Bonus is less than zero, the Buyer must pay the Supplier an Availability Bonus equal to the product of (i) the weighted average of (A) the annual average On-peak Day-Ahead Locational Marginal Price and (B) the annual average Off-peak Day-Ahead Locational Marginal Price (calculated using the weighted average of On-peak and Off-peak hours for the node from which the Facility is dispatchable for the relevant two-year period), (ii) the Availability Bonus expressed as a percentage, (iii) Confirmed Contract Quantity, and (iv) the number of Period Hours in previous Contract Year.

6. If a Force Majeure event affects the Facility's Actual Availability in a material mariner (which shall be defined as a decrease of more than 5% from the Contract Target Availability), the Supplier must send written

notification in accordance with Article 9 of this Agreement to the Buyer and to the MDPSC, providing documentation about the said Force Majeure event, and requesting an exception to the liquidated damages resulting from the Availability Deficiency. The Supplier must pursue negotiations with the Buyer regarding this issue, and should the Buyer and Supplier not be able to resolve the issue bilaterally, they should follow the guidelines set forth in Section 12.9 of this Agreement.

7. Each Party acknowledges and agrees with respect to the liquidated damages pursuant to Section 3.1(f)(4)(ii) that:

   A. the actual damage expected as a result of the Supplier's breach of these requirements would be substantial;

   B. both Parties intend that the Supplier would pay the specified liquidated damages amount for such a breach;

   C. this amount of damages is not a penalty;

   D. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer would sustain if the Supplier breaches this provision;

   E. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and,

   F. such liquidated damages shall be the sole damages to which the Buyer shall be entitled as a result of the Supplier's breach of these requirements.

(g) The Supplier shall demonstrate that it has maintained the Facility's Contract Annual Heat Rate in accordance with the terms of this Agreement by conducting a heat rate test on an annual basis. This heat rate test will show that the Facility's thermal efficiency (otherwise known as the heat rate of the Facility) has not fallen more than 5% below the rate warranted by the Supplier in its Proposal, listed in Exhibit C.

1. The Supplier shall schedule to conduct the initial heat rate test within the first ninety (90) calendar days of attaining Commercial Operation. An independent engineer shall conduct or supervise the initial heat rate test. The Supplier's EPC Contractor may serve as the independent engineer as long as the EPC Contractor is not the Supplier, if approved by the Buyer.

2. Following the Execution Date, each subsequent heat rate test must be completed not sooner than ten (10) months or later than thirteen (13) months from the previous heat rate test.

3. Test procedures shall be consistent with the American Society of Mechanical Engineers Performance Test Code 46, as may be amended or supplemented, and must be submitted to the Buyer for approval not less than sixty (60) calendar days prior to conducting the initial heat rate test. Buyer shall either approve the submitted test procedure, or using reasonable judgment consistent with Prudent Utility Practice, provide a written notification of deficiencies

in the proposed procedure to Supplier by not less than twenty (20) calendar days prior to the initial heat rate test. Supplier shall correct the listed deficiencies to the satisfaction of the Buyer.

4. Supplier shall provide the results of each heat rate test to Buyer and the MDPSC not more than two (2) Business Days after completion of each heat rate test performed after the Execution Date. If the tested heat rate is greater than the Contract Annual Heat Rate listed in Exhibit C to this Agreement for the specific Site and atmospheric conditions at the Facility during the test by more than 5%, this shall constitute a Supplier Event of Default as set forth in Article 8 if not cured within the ninety (90) calendar day cure period.

(h) The Supplier must submit documentation on an annual basis to the Buyer and the MDPSC to demonstrate its continued compliance with Section 2.6(h). The Supplier must provide this written documentation no later than thirty (30) calendar days after the end of each Contract Year.

(i) If, after the Commercial Operation Date, the Facility's Unforced Capacity decreases to a level at which it is less than the Confirmed Contract Quantity for non-Force Majeure related reasons:

1. If the reduction in Unforced Capacity is less than or equal to 3% of the Confirmed Contract Quantity, the Confirmed Contract Quantity is automatically reduced through

an addendum to this Agreement for the purposes of settlement under Article 6 until the Facility's Unforced Capacity can be re-tested in accordance with PJM procedures and the Confirmed Contract Quantity is restored.

2. If the reduction in Unforced Capacity is more than 3% of the Confirmed Contract Quantity, the Supplier shall have twenty-one (21) calendar days to cure before incurring liquidated damages. As of the twenty-second (22nd) day after the Facility's Unforced Capacity decreased below the Confirmed Contract Quantity level, the Supplier shall pay to the Buyer liquidated damages equal to the positive difference (if any) between the Replacement Price for the foregone Confirmed Contract Quantity (Confirmed Contract Quantity minus Unforced Capacity) and the amount that Buyer would have paid hereunder during the period from the calendar day when the Unforced Capacity decreased to a level below the Confirmed Contract Quantity until the calendar day that such deficiency is cured, which must be less than forty-five (45) calendar days in total, from the calendar day when the Unforced Capacity decreased to level below the Confirmed Contract Quantity. As of the forty-sixth (46th) calendar day after the Unforced Capacity decreased, (1) the Supplier shall pay to the Buyer liquidated damages on a monthly basis equal to the positive difference (if any) between the Replacement Price for the foregone Confirmed Contract Quantity

(Confirmed Contract Quantity minus Unforced Capacity) and the amount that Buyer would have paid hereunder until the Confirmed Contract Quantity level is restored, and (2) the Confirmed RPM Contract Quantity will be reduced through an addendum to this Agreement for the purposes of settlement under Article 6 until the Facility's Unforced Capacity can be re-tested in accordance with PJM procedures and the Confirmed Contract Quantity level is restored.

3. Each Party acknowledges and agrees with respect to the liquidated damages pursuant to Section 3.2(d) that:

   i. the actual damage expected as a result of the Supplier's breach of these requirements will be substantial, but such damages are uncertain in amount and/or difficult to ascertain;

   ii. both Parties intend that the Supplier will pay the specified liquidated damages amount for such a breach;

   iii. this amount of damages is not a penalty;

   iv. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Buyer will sustain if the Supplier breaches this provision;

   v. the amount of liquidated damages is a genuine pre-estimate of the loss that the Buyer will incur; and

vi. such liquidated damages shall be the sole damages to which the, Buyer shall be entitled as a result of the Supplier's breach of these requirements.

3.2 PJM Market Participation

(a) The Supplier warrants that the Facility is eligible to and will participate in and offer into all PJM Markets pursuant to guidelines established by the MDPSC, including but not limited to the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market consistent with PJM Rules. The Supplier will participate in those PJM Markets as recommended by Buyer and approved by the MDPSC from time to time.

(b) Beginning on the BRA auction date covering capacity obligations for the Delivery Year that first follows the Commercial Operation Date, the Supplier will have the Units offer and participate in the BRA. The Supplier will continue to have the Units offer and participate in the BRA until otherwise directed by the MDPSC.

1. The Supplier may not withhold generation resources from the Facility from any PJM Market in which it has elected to participate either through its offering behavior or by incorrectly declaring resources to be unavailable, as per the guidelines used by the PJM in assessing and mitigating market power.

2. Beginning on the Commercial Operations Date, the Supplier will have the Units offer and participate in the Day-Ahead Energy

Market, Real-Time Energy Market and Ancillary Services Market. The Units shall submit cost-based offers only.

(c) The Supplier represents, warrants, and covenants that the Facility will be capable of fully participating in the PJM Markets, based on the design of the Facility and the Facility's compliance with the technical qualifications in current PJM Agreements. The Supplier is solely liable for PJM submittal errors and all charges related to incorrectly entering or submitting data to PJM will not be passed on to the EDC(s).

(d) This Agreement is exclusive with the Supplier providing the Buyer, upon Commercial Operation, with the Supplier's revenues from sales and other activities, including but not limited to those from the sale of the Facility's electricity products and services into the PJM energy and capacity markets, but excluding those from the PJM Ancillary Service Markets, and any other revenues available to the Facility, which revenues are netted against the Monthly Payment Amount described in Article 6. In exchange for providing the Buyer all revenues, the Supplier receives the Monthly Payment Amount from the Buyer who collects said compensation through retail rates approved by the MDPSC. This Agreement is settled financially on a monthly basis, in accordance with Article 6. The resulting cash flows from month to month may either be to Buyer or to Supplier. Revenues earned prior to Commercial Operation shall be retained by Supplier as will revenues obtained from the sale of Ancillary Services. If the MDPSC orders that

the Buyer take title to the Supplier's electricity products and services pursuant to Section 4.1(b), the Supplier shall provide the Buyer with title to all such products and services including but not limited to Energy and Capacity. This Agreement precludes the Supplier from entering into a bilateral contract or other arrangement to sell any of its output, products or services, including but not limited to Reliability Must Run Agreements or any similar arrangement with another third party, PJM, or any Government Agency during the Term of the Agreement, unless approved by the MDPSC.

(e) The Supplier cannot seek to Delist any portion of the Contract Summer Qualified Capacity in the BRA, unless otherwise approved by the MDPSC in writing. The Supplier must offer accordingly to ensure the Contract Summer Qualified Capacity is not delisted from the BRA, unless otherwise approved by the MDPSC. Such approval can be sought by the Supplier or the Buyer by requesting it in writing from the MDPSC at least sixty (60) calendar days in advance of the qualifications deadline[s] for the BRA in which the Buyer or Supplier would like the Supplier seek to Delist. Once the MDPSC approves a request to seek to Delist, the Supplier must offer accordingly in the next BRA.

(f) The Supplier shall not submit an Export Offer for any portion of the Contract Summer Qualified Capacity in the BRA, unless the MDPSC provides prior written approval. Such approval can be sought by the Supplier or the

Buyer by requesting it in writing from the MDPSC at least sixty (60) calendar days in advance of the qualifications deadline[s] for the BRA in which the Buyer or Supplier would like the Supplier to submit an Export Offer. Once the MDPSC approves a request to submit an Export Offer, the Supplier must offer accordingly in the next BRA.

(g) The Supplier must request and take reasonable steps to ensure that PJM issues weekly and/or monthly invoices, as applicable, that identify the market(s) in which the Supplier participated and the revenues earned and any penalties accrued by the Supplier. Any penalties accrued by the Supplier shall be the sole responsibility of the Supplier and the Supplier shall not be entitled to recover any such amounts from Buyer. The Supplier must provide the invoices to the Buyer with the monthly bill the Supplier submits to the Buyer. The Supplier's failure to provide said invoices for more than two (2) consecutive months, except if the failure is caused by the PJM's refusal to issue such invoices, constitutes a curable Event of Default, Section 8.1.(c)(4), and the Buyer shall withhold payments to the Supplier until said invoices are provided. The Supplier shall make the invoices available to MDPSC upon request.

3.3 Other Covenants of the Supplier

(a) The Supplier shall comply with applicable Law and the procedures, rules and regulations of PJM and the requirements of the PJM Agreements.

(b) The Supplier, or its agent, will apply for and maintain its Market Based Rate Authorization with FERC or such other appropriate authorization from FERC under Section 205 of the Federal Power Act to enable the Supplier to participate in the PJM Markets.

(c) The Supplier will comply in full with all relevant and applicable FERC requirements.

(d) The Supplier must keep separate financial records for the Facility, including quarterly revenues and costs and balance sheet statements, and make them available upon request in accordance with Section 11 of this Agreement.

(e) Supplier shall provide to Buyer reasonably requested information that the Buyer requires for its accounting analysis or Securities Exchange Commission reporting purposes.

(f) The Supplier must give the Buyer and the MDPSC thirty (30) calendar days' notice before it would receive additional state-approved or federal-approved ratepayer funding ("Additional Ratepayer Funding") for the operation of the Facility and must submit all information regarding the Additional Ratepayer Funding to the Buyer and the MDPSC at the time of notice.

1. Upon the MDPSC's receipt of a notice that the Supplier shall receive Additional Ratepayer Funding, the MDPSC shall instruct the Buyer and the Supplier to reduce the amount of payments owed from the Buyer to the Supplier by an amount equal to the Additional Ratepayer Funding. The structure of such payment reductions

will be determined by the MDPSC based on the nature of and structure of Additional Ratepayer Funding.

2. The Supplier agrees that the MDPSC can reduce compensation to the Supplier under the terms of this Agreement such that total ratepayer funding for the Facility does not exceed the total amount payable to the Supplier anticipated under this Agreement.

ARTICLE 4

BUYER'S OBLIGATIONS

4.1 Payment to Supplier

(a) After the Supplier has attained Commercial Operation and has begun participating in the PJM Markets as required by this Agreement, the Buyer shall pay the Supplier and the Supplier shall pay the Buyer the amounts due according to Article 6, as the case may be, in accordance with the terms of this Agreement.

(b) The Buyer shall not take title to or risk of loss to any products or services generated, delivered, or sold by the Facility unless ordered to do so by the MDPSC upon the recommendation of the Buyer or Supplier. Either Party can initiate an amendment to the Agreement to require that the Buyer receive title to the Supplier's output. In such event, the Buyer shall provide the Supplier copies of the full set of information provided by PJM that the Supplier would have otherwise received directly from PJM prior to such transfer of title of the Supplier's output.

4.2 Required Approvals

(a) Each Party's obligations under this Agreement shall be of no force and effect until the Effective Date of this Agreement.

(b) Notwithstanding Section 4.2(a) above, the Buyer agrees to release the Supplier from this Agreement if a MDPSC approval is not obtained within one-hundred and eighty (180) calendar days of the Execution Date if the Supplier does not choose to continue to wait for MDPSC approval.

(c) If the Supplier agrees to wait for MDPSC approval after one-hundred and eighty (180) calendar days has elapsed, the fixed portion of the Monthly Payment Amount will be escalated by the Handy-Whitman Index of Public Utility Construction Costs for the period of time between the deadline for the submission of financial offers during the procurement process and the one-hundred and eightieth (180th) calendar day after the Execution Date. This revised figure will constitute the new Monthly Payment Amount. The Buyer agrees to release the Supplier from this Agreement if MDPSC approval is not obtained three-hundred and sixty (360) calendar days after the Execution Date.

4.3 Other Obligations of the Buyer

(a) The Buyer shall comply with all applicable PJM Tariffs and PJM Agreements.

(b) The Buyer shall comply with all of its obligations under this Agreement.

(c) Using the information and documentation provided to it by the Supplier, the Buyer shall assess the Supplier's performance with respect to the Supplier's obligations and report as appropriate to the MDPSC if the Buyer believes the Supplier is not meeting its obligations under this Agreement or if the Buyer believes that it is in the interest of ratepayers for the MDPSC to direct the Supplier to participate in different PJM Market(s) than the market or markets in which the Supplier is currently participating. The Supplier shall be copied on such submittal to the MDPSC, and following a hearing if one is requested by the Buyer or the Supplier, the MDPSC shall determine whether the Supplier is meeting its obligations and whether the Supplier should participate in different PJM Market(s) than those in which the Supplier is currently participating.

(d) The Buyer is responsible for communicating in writing any problems or insufficiency in performance of the Supplier to the MDPSC within five (5) Business Days following Buyer's discovery thereof. The Buyer shall request direction for treatment for any such problems or insufficiency from the MDPSC, unless treatment is detailed under this Agreement.

(e) The Buyer shall comply with all requirements listed in the Code of Conduct, which is attached to this Agreement as Exhibit E.

(f) The Buyer acknowledges that the payments it receives from the Supplier, including any liquidated damages and/or Early Termination Payments, are for the benefit of and should be credited back to Maryland ratepayers.

(g) The Buyer shall provide commercially reasonable assistance, consistent with PJM rules, procedures and standards, in supporting the Supplier's efforts to attain Commercial Operation on a timely basis, and shall provide any documents or information that the Supplier may reasonably request that are necessary for the Facility to interconnect to the electric system or otherwise attain Commercial Operation.

ARTICLE 5

TERM

5.1 Execution Date and Effective Date

(a) This Agreement is executed on the Execution Date.

(b) This Agreement shall become effective 30 days after the date of the issuance of the MDPSC decision in Case No. 9214, approving this Agreement, if no appeal is taken, or, if an appeal is taken, when the appeal is finally resolved and no further appeals can be taken (hereinafter, the "Effective Date").

5.2 Term

(a) The Term of this Agreement shall be [1 years from the Commercial Operation Date (as described in Supplier's Proposal) (the "Term"), unless this Agreement is terminated earlier pursuant to Article 8 of this Agreement [or extended pursuant to Section 12.11 of this Agreement].

(b) The first day of the Term is the "Term Commencement Date."

ARTICLE 6

PAYMENT TERMS AND BILLING

6.1 Determination of Monthly Payment Amount

(a) No Monthly Payment shall be provided during any period in which the Supplier has not been selected to provide capacity in PJM's BRA. If the Supplier is selected only in part, only the capacity selected and capacity that is designated for "make whole" payments, if any, will be deemed to have cleared the Auction when payment calculations are made under this section. Capacity that has neither cleared nor been designated for "make whole" payments will not be deemed to have cleared the Auction when payment calculations are made under this section. The Supplier will be responsible for seeking any "make whole" payments from PJM.

(b) The Buyer agrees to pay the Supplier and the Supplier agrees to pay the Buyer, as the case may be, the amounts determined pursuant to the terms of Article 6 of this Agreement for the Term of this Agreement.

(c) The Monthly RPM Payment Amount and Monthly Energy Payment Amount are each defined in Exhibit F.

(d) The Monthly Payment Amount shall be equal to the sum of the Monthly RPM Payment Amount and the Monthly Energy Payment Amount.

1. If the Monthly Payment Amount is positive then the Buyer will pay the Supplier the Monthly Payment Amount.

2. If the Monthly Payment Amount is negative then the Supplier will pay the Buyer the Monthly Payment Amount.

3. If the Monthly Payment Amount is zero, then no payments are due to either Party.

6.2 Adjustments to Monthly Payment Amount

(a) If there is a delay in the Commercial Operation Date of no more than twenty-nine (29) calendar days, the Monthly Payment Amount will be reduced on a pro-rata basis, calculated by the number of days the Facility is not yet in operation over the number of days in a particular month it was originally intended to be in service. This will be a one-time adjustment to reflect the delay in the Commercial Operation Date. Liquidated damages for the delay, as described in Section 2.5 of this Agreement, will also be applied.

(b) The Parties acknowledge that the Buyer shall not pay for Capacity and Energy that PJM deems was not made available up to the performance standards required by PJM Agreements and PJM Tariff. An Adjustment Ratio shall be used to adjust Monthly Payment Amount such that the Monthly Payment Amount factor in PJM availability or other performance penalties.

(c) The Adjustment Ratio will be calculated by adding actual PJM payments to the Supplier based on the Supplier's Confirmed Contract Quantity and/or delivered Energy, as the case may be, and dividing that total by the payments the Supplier would have expected to receive from PJM if performance was satisfactory given

PJM requirements using the formulas set forth below:

1. The "Adjustment Ratio" will be calculated by taking the actual PJM payment for participation in the PJM Markets for the previous month divided by the expected PJM payment for participation in the PJM Markets for the previous month, as illustrated in the formula below.

   Adjustment Ratio = (Actual PJM payment for PJM Markets / Expected PJM payment for PJM Markets)

   Where:

   - Actual PJM payment is equal to the Clearing Price in the applicable PJM Markets for the applicable month times the cleared quantity minus any penalties assessed by PJM for that month's performance in the applicable PJM Markets
   - Expected PJM payment is equal to the Clearing Price in the PJM Markets for applicable month times the cleared quantity

2. If the Supplier is making payment to the Buyer, and the Adjustment Ratio is between 0 and 1, the Supplier's payment to the Buyer shall be increased pro rata by the Adjustment Ratio by dividing the Monthly Payment Amount by the Adjustment Ratio, to represent the effective shortfall in contract quantity and resulting loss in Buyer's benefits due to underperformance by the Supplier.

3. If the Buyer is making payment to the Supplier, and the Adjustment Ratio is between 0 and 1, the Buyer's payment to the Supplier shall be reduced pro rata by the Adjustment Ratio by multiplying the Monthly Payment Amount by the Adjustment Ratio, to represent the effective shortfall in contract quantity and resulting loss in Buyer's benefits due to underperformance by the Supplier.

4. If the Adjustment Ratio is less than zero, the Monthly Payment Amount will be reduced to zero.

(d) The Supplier must provide the Buyer and the MDPSC with a copy of PJM's weekly billing statement regarding the Supplier's activities in the RPM within two (2) Business Days of receipt of such a document. If invoices from PJM's weekly statements are delayed beyond two (2) Business Days after the end of a month, adjustments to the Monthly Payment Amount pursuant to Section 6.2 above shall be made in the next monthly bill, pursuant to Section 6.5 of this Agreement.

(e) If the Facility's Actual Availability is less than its Contract Target Availability for a relevant period, as set forth in Section 3.4(c), the next Monthly Payment Amount will be adjusted by the liquidated damages described in Section 3.4(c). If the Facility's Actual Availability is greater than its Contract Target Availability for a relevant period, as set forth in Section 3.4(c), the next Monthly Payment Amount will be adjusted by the Availability Bonus described in Section 3.4(c).

(f) If the Supplier must pay liquidated damages as a result of non-compliance with Section 2.6(g), Section 3.2(d) and Section 3.2(e), such damages may be netted against any Monthly Payment Amount.

6.3 Billing Period

As soon as practicable after the end of each month during the Term but not later than thirty (30) Business Days after the end of such month, the Supplier shall provide the Buyer with one bill for the Monthly Payment Amount, pursuant to Section 6.1. The bill will include a detailed calculation of the aggregate Monthly Payment Amount for purposes of billing, determined in accordance with the provisions of Article 6 of this Agreement. Depending on the determination of the Monthly Payment Amount pursuant to Section 6.1, the Buyer will pay to the Supplier or the Supplier will pay the Buyer, as the case may be.

6.4 Timeliness and Form of Payment

(a) All bills submitted pursuant to this Article 6 shall bear the date of rendering and shall be due and payable on or before the later of : (i) the last Business Day of the month or (ii) twenty (20) Business Days following the data on which the Buyer received the Supplier's bill. Any amount remaining unpaid after such period shall bear interest at the rate set forth in the regulations of FERC for interest payments on refunds.

(b) All payments sent by the Buyer to the Supplier shall be sent by electronic funds transfer to the bank account specified by the Supplier.

(c) All payments sent by the Supplier to the Buyer shall be sent by electronic funds transfer to the bank account specified by the Buyer.

6.5 Adjustments of Invoices and Disputes

(a) Each bill rendered under this Agreement shall be subject to adjustment in order to true-up charges based on changes resulting from any recent PJM billing statements or revisions, if any, to previous PJM billing statements.

(b) Any further revisions to any bill will be reflected as soon as practicable and in accordance with the PJM Agreements and the provisions of Article 6 of this Agreement. All refunds or additional payments owed to either Party shall include the payment of interest from the due date in the case of additional payments and from the payment date in the case of refunds, in either case to the date of payment calculated in accordance with the regulations of the FERC applicable to the payment of interest on refunds.

(c) If either Party disputes the amount of any bill, it shall so notify the other Party in writing.

1. If the disputed amount is unrelated to an Event of Default, 50% of the disputed amount will be paid by the paying Party ("Paying Party"), with the remainder held in Escrow for the benefit of the non-paying Party ("Non-Paying Party") until both Parties have resolved the dispute. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier

relative to the determination regarding the disputed amount.

2. If the disputed amount is related to a Supplier Event of Default, and, the Buyer is the Paying Party:

   a. If it is a Supplier Event of Default that has no cure or is an Event of Default that has not been cured within the applicable cure period, then the Buyer shall not pay the disputed amount until the specific Event of Default by Supplier has been cured to the satisfaction of the Buyer, or the dispute has been resolved. Escrow interest accrued in the Escrow account or interest that would have accrued, had payment of a disputed amount been subject to Escrow, will be paid to the Supplier once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

   b. If the Supplier Event of Default is due to the Supplier's loss of Market Based Raternaking Authority, 50% of the disputed amount will be paid by the Buyer, with the remainder held in Escrow until this Event of Default has been cured or the dispute has been resolved. Escrow interest accrued in the Escrow account will be paid to the Supplier once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier

relative to the determination regarding the disputed amount.

3. If the disputed amount is related to a Buyer Event of Default that has no cure or is an Event of Default that has not been cured within thirty (30) calendar days or within the timeframe allotted pursuant to Section 8.5(b), and if the Supplier is the Paying Party, then the Supplier shall not pay the disputed amount until the specific Event of Default by Buyer has been cured to the satisfaction of the Supplier, or the dispute has been resolved. Escrow interest accrued in the Escrow account will be paid to the Buyer once the Event of Default has been cured, or will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

4. If the non-payment by Buyer is related to non-performance of a contract covenant in this Agreement that is itself in dispute and not covered by Section 6.2(a) through (c) above, 50% of the disputed amount will be paid by the Paying Party, with the remainder held in Escrow for the benefit of the Non-Paying Party until both Parties have resolved the dispute. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

5. For all other issues or billing disputes, 50% of the disputed amount will be paid by the Paying Party, with the remainder held in Escrow for the benefit of the Non-Paying Party until the dispute has been resolved. Once the dispute has been resolved, interest accrued in the Escrow account will be paid on a pro-rata basis to the Buyer and the Supplier relative to the determination regarding the disputed amount.

(d) Neither Party shall have the right to challenge any bill or to bring any court or administrative action of any kind questioning the propriety of any bill after a period of twenty-four (24) months from the date the bill was due; provided, however, that in the case of a bill based on estimates, such twenty-four (24) month period shall run from the due date of the final adjusted bill.

6.6 Payment Obligation with Netting

The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing under this Agreement to each other on the same date, in which case all amounts owed by each Party to the other Party during the monthly billing period under this Agreement, including any related damages, interest, and payments or credits, shall be netted (to the extent possible) so that only the excess amount remaining due shall be paid by the relevant Party.

6.7 Use of Completion and Performance Security for Payment of Invoices

(a) Unless the Buyer notifies the Supplier in writing, and except in connection with liquidation and termination in accordance with Article

8 of this Agreement, all amounts netted pursuant to this Article 6 shall not take into account or include any portion of the Completion and Performance Security, which secures the Supplier's performance under this Agreement.

(b) In the case of non-payment by the Supplier, the Buyer has the right to monies from the Completion and Performance Security (unless there is a dispute over the billing amount, in which case both Parties shall proceed in accordance with Article 6.5(c)) if payment is not made on a timely basis.

ARTICLE 7

REPRESENTATIONS AND WARRANTIES

7.1 Representations of the Supplier

The Supplier represents to the Buyer as follows, and acknowledges that the Buyer is relying on such representations in entering into this Agreement:

(a) The Supplier is a [legal form of Supplier], [incorporated/organized] under the Laws of [state of], and is registered or otherwise fully qualified to carry on business in the State of Maryland, and has the requisite power to enter into this Agreement and to perform its obligations hereunder. The executed Agreement, however, is subject to final approval by the MDPSC.

(b) This Agreement has been duly authorized, executed, and delivered by the Supplier and is a valid and binding obligation of the Supplier enforceable in accordance with its terms except

as such enforcement may be limited by Bankruptcy.

(c) The execution and delivery of this Agreement by the Supplier and the consummation of the transactions contemplated by this Agreement will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any material obligation of the Supplier under:

1. any contract or obligation to which the Supplier is a party or by which it or its assets may be bound, except for such defaults or conflicts as to which requisite waivers or consents have been obtained;
2. the articles, by-laws or other resolutions of the directors or shareholders of the Supplier;
3. any judgment, decree, order or award of any Government Authority or arbitrator;
4. any license, Permit, approval, consent or authorization held by the Supplier; or
5. any Laws that could reasonably be expected to have a material adverse effect on the Supplier or the performance of the Supplier's obligations under this Agreement.

(d) There is no Bankruptcy, insolvency, reorganization, receivership, seizure, realization, arrangement or other similar proceedings pending against or being contemplated by the Supplier or, to the knowledge of the Supplier, threatened against the Supplier.

(e) There are no actions, suits, proceedings, judgments, rulings or orders by or before any Government Authority or arbitrator, or, to the knowledge of the Supplier, threatened against the Supplier, which could reasonably be expected to have a material adverse effect on the Supplier, or the ability of the Supplier to perform its obligations under this Agreement.

(f) All requirements for the Supplier to make any filing, declaration or registration with, give any notice to or obtain any license, Permit, certificate, registration, authorization, consent or approval of, any Government Authority as a condition to entering into this Agreement have been satisfied.

(g) All statements, specifications, data, confirmations, and information that have been set out in the Exhibits to this Agreement are complete and accurate in all material respects and are hereby restated and reaffirmed by the Supplier as representations made from the Supplier to the Buyer under this Agreement and there is no material information omitted from the Exhibits which makes the information in the Exhibits and this Agreement misleading or inaccurate.

7.2 Representations of the Buyer

The Buyer represents to the Supplier as follows, and acknowledges that the Supplier is relying on such representations in entering into this Agreement:

(a) The Buyer has the requisite power to enter into this Agreement and to perform its obligations hereunder. The executed Agreement, however, is subject to final approval by the MDPSC.

(b) This Agreement has been duly authorized, executed, and delivered by the Buyer and is a valid and binding obligation of the Buyer enforceable in accordance with its terms, except as enforcement may be limited by Bankruptcy.

(c) The execution and delivery of this Agreement by the Buyer and the consummation of the transactions contemplated by this Agreement will not result in the breach or violation of any of the provisions of, or constitute a default under, or conflict with or cause the termination, cancellation or acceleration of any material obligation of the Buyer under:

1. any contract or obligation to which the Buyer is a party or by which it or its assets may be bound, except for such defaults or conflicts as to which requisite waivers or consents have been obtained;

2. the by-laws or resolutions of the directors (or any committee thereof) or, shareholders of the Buyer;

3. any judgment, decree, order or award of any Governmental Authority or arbitrator;

4. any license, Permit, approval, consent or authorization held by the Buyer; or

5. any Law that could reasonably expect to have a material adverse effect on the Buyer or the Buyer's performance of its obligations under this Agreement.

(d) There is no Bankruptcy, insolvency, reorganization, receivership, seizure, realization, arrangement or other similar proceedings pending against, or being contemplated by the Buyer or, to the

knowledge of the Buyer, threatened against the Buyer.

(e) There are no actions, suits, proceedings, judgments, rulings or orders by or before any Government Authority or arbitrator, or, to the knowledge of the Buyer, threatened against the Buyer that could reasonably expect to have a material adverse effect on the Buyer or the Buyer's ability to perform its obligations under this Agreement.

(f) All requirements for the Buyer to make any declaration, filing or registration with, give any notice to or obtain any license, Permit, certificate, registration, authorization, consent or approval of, any regulatory authority as a condition to entering into this Agreement have been satisfied.

ARTICLE 8

EVENTS OF DEFAULT; REMEDIES

8.1 Events of Default of Supplier

(a) Any of the following shall constitute an. Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within three (3) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier is no longer eligible to participate in any PJM Market in which it is obligated to participate under this Agreement for any reason other than those

described in Section 8.1(b), 8.1(c), and 8.1(d) below. If the Supplier can demonstrate to the MDPSC, within three (3) Business Days after the date of written notice given by the Buyer: 1) that the Supplier can cure the Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer, and 2) that the PJM Agreements and PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets within thirty (30) Business Days after the date of written notice given by the Buyer, the Supplier's loss of eligibility to participate in the PJM Markets shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year, in which case the 3-Business Day cure period will apply.

2. The Facility cannot deliver benefits to the state of Maryland in accordance with Section 2.2 due to an action of the Supplier or lack of reasonable action in instances where action was warranted and the Supplier had the ability to provide such action;

3. The Supplier becomes Bankrupt;

4. The Supplier consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the

resulting, surviving or transferee entity fails to assume all the obligations of the Supplier under this Agreement pursuant to an assignment or assumption agreement reasonably satisfactory to the Buyer and approved by the MDPSC;

5. Supplier seeks or enters into a Reliability Must Run, a Cost of Service contract, or a similar agreement for any part of the Facility's output, products or services without MDPSC approval during the Term of this Agreement;
6. The Supplier dissolves or liquidates;
7. The Supplier sells any part of its output, products or services from the Facility to a third party without approval by the MDPSC;
8. The Supplier intentionally provides false information required by this Agreement or intentionally fails to provide information required by this Agreement on material topics; or,

(b) Any of the following shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within seven (7) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement;

1. The Supplier fails to maintain the Project Completion and Performance Security, pursuant to Article 10 of this Agreement.

(c) Any of the following shall constitute an Event of Default of Supplier if the Supplier has failed to cure such an Event of Default within thirty (30) Business Days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier fails to comply with any obligation under this Agreement that would result in a material adverse impact on the Buyer or ratepayers;

2. The Supplier is unable to participate in the PJM Markets due to events including but not limited to the termination of its membership (or the membership of its agent), or suspension of membership rights or termination of its Operating Agreement with PJM unless the PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year in which case the 3-Business Day cure period would apply;

3. The Supplier is eligible to participate but does not participate in PJM Markets as directed by the MDPSC in accordance with Section 3.1(b) unless the PJM Tariff will permit the Supplier to resume participation and earn revenues in the PJM Markets

within thirty (30) Business Days after the date of written notice given by the Buyer. This 30-Business Day cure period does not apply if, after the cure is achieved, the Supplier must remain out of the RPM for a year in which case the 3-Business Day cure period would apply;

4. The Supplier fails to submit PJM invoices required by Section 3.3(g) with its bill to the Buyer evidencing its participation in and revenues earned in PJM Markets for two (2) consecutive months;

5. The Supplier fails to meet requirements of Section 2.6(h); or

6. The Supplier fails to maintain insurance coverage as required by Section 2.8.

(d) Any of the following shall constitute an Event of Default of Supplier if Supplier has failed to cure such an Event of Default within ninety (90) calendar days after the date of written notice given by the Buyer to the Supplier and the MDPSC, unless the MDPSC determines that it is in the best interest of ratepayers to excuse non-performance and not terminate the Agreement:

1. The Supplier breaches any other covenant or obligation in a material manner in this Agreement not explicitly listed in Sections 8.1(a), 8.1(b) or 8.1(c).

2. The Facility's performance on an annual heat rate test falls more than 5% below the Contract Annual Heat Rate established in Exhibit C.

(e) The failure of the Supplier to achieve the Milestone Date for Commercial Operation shall constitute an Event of Default of the Supplier if the Supplier has failed to cure such an Event of Default within one hundred eighty (180) calendar days after the date of written notice given by the Buyer to the Supplier and MDPSC unless an extension of time is approved by the MDPSC pursuant to Article 2. In the event the Supplier does not achieve its Milestone Date for Commercial Operation, and the failure is not excused, the Buyer shall provide written notice to the Supplier and MDPSC the next Business Day after the Milestone Date for Commercial Operation.

(f) For any Event of Default excused by a MDPSC determination that it is in the interest of ratepayers to excuse non-performance and not terminate the Agreement, the tollowing terms and conditions apply. The Supplier must cure any Event of Default on or before a new deadline for curing the Event of Default set by the MDPSC. If prior to curing the Event of Default the Supplier earns monthly revenue in excess of its monthly costs, the Supplier must return any excess revenue to the Buyer.

8.2 Remedies Available to the Buyer

(a) there is an Event of Default by the Supplier and such Event of Default is not cured in a timely manner by the Supplier pursuant to any applicable cure period provided by this Agreement, the Buyer, subject to the approval of the MDPSC, shall have the right to seek any of the remedies (or combinations thereof) listed below.

1. Designate an "Early Termination Date" pursuant to Section 8.6;
2. Withhold any payments due to the Supplier under this Agreement unless the Supplier continues to perform according to its obligations under this Agreement in which case the Buyer must compensate the Supplier for its services according to this Agreement; any payments required from the Buyer to the Supplier for services prior to the Event of Default will be credited to the Buyer in calculating the Early Termination Payment; and/or,
3. Exercise any remedy available at Law, in equity, or under this Agreement to the extent an Event of Default shall have occurred and be continuing.

(b) If the Event of Default by Supplier is the voluntary or involuntary filing of a petition commencing a case under the Bankruptcy Code, then the Buyer shall have the right to terminate this Agreement by notice to the Supplier and such termination shall take effect immediately upon issuance of such notice by Buyer to Supplier. The Buyer shall have the right to damages (if any) calculated pursuant to 11 U.S.0 § 562, as it may be amended from time to time, and other applicable Law. The Parties agree that each is a Financial Participant for the purposes of the Bankruptcy Code and waive any right to contest the other's status as a Financial Participant in any proceeding under the Bankruptcy Code. The Early Termination Payment, as described in Section 8.7, will not apply in this instance.,

8.3 Financing Parties' Right to Cure Default of Supplier

(a) The Supplier shall provide to the Buyer and the MDPSC a notice identifying the Financing Parties and providing appropriate contact information for the Financing Parties at the Execution Date of this Agreement, and from time to time during the Term, as such information may change. Following the effective date of such notice, the Buyer shall provide prompt notice of any event described in Section 8.1 hereof to the Financing Parties, and the Buyer will accept a cure performed by the Financing Parties, so long as the cure is accomplished within the applicable cure period set forth in Section 8.1 hereof.

(b) Within ten (10) calendar days following the effective date of written notice from the Financing Parties of default, or the Financing Parties' intent to exercise any remedies, the Supplier shall deliver a copy of such notice to the Buyer and the MDPSC.

8.4 Events of Default by Buyer

(a) Any of the following shall constitute an Event of Default of Buyer with no cure period:

1. The Buyer's dissolution or liquidation. If there is a successor to the Buyer, this shall not constitute dissolution or liquidation as long as the successor assumes all the rights and responsibilities of the Buyer under this Agreement; and/or

2. Without the approval of the MDPSC under 6-105 of the PUA, the Buyer consolidates or amalgamates with, or merges into or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting surviving or transferee entity fails to assume all the obligations of the Buyer under this Agreement pursuant to an assignment or assumption agreement approved by the MDPSC.

(b) The following shall constitute an Event of Default of the Buyer if the Buyer has failed to cure such an Event of Default within ten (10) calendar days after the Buyer receives written notice of such Event of Default from the Supplier:

1. The Buyer fails to make any payment due hereunder.

(c) Any of the following shall constitute an Event of Default of the Buyer if the Buyer has failed to cure such an Event of Default within thirty (30) calendar days after Buyer's receipt of written notice of such Event of Default from the Supplier:

1. The Buyer fails to comply with any other covenant or obligation under this Agreement that will result in a material adverse impact on the Supplier;

2. The Buyer intentionally provides false information required by this Agreement or intentionally fails to provide information required by this Agreement on material topics; or,

3. The Buyer becomes Bankrupt and the MDPSC is unable to take timely actions to ensure that another entity stands in for the Buyer and performs the Buyer's obligations to the Supplier under this Agreement.

8.5 Remedies available to Supplier

(a) If the Credit Rating of the Buyer falls below Investment Grade level (as per the notifications required in Section 12.2), the Supplier shall submit a notice to the MDPSC, notifying the MDPSC of the potential of an Event of Default. If the MDPSC chooses to do so, the MDPSC may respond to this notice by facilitating a pre-emptive cure of this potential Event of Default.

(b) In case of an Event of Default of the Buyer pursuant to Section 8.4, the Supplier must also send a written notice thereof to the MDPSC. If the MDPSC issues a reply notice within ten (10) Business Days of receipt of such notice from the Supplier, this reply notice will temporarily suspend the Supplier's ability to seek any of the remedies available to the Supplier at Law, in equity, or under this Agreement for a period of ninety (90) calendar days, while the MDPSC undertakes by exercise of its statutory authority to facilitate the process of curing the Event of Default of Buyer. During the above-mentioned ninety (90) calendar-day period, the Supplier temporarily shall place any payments due to the Buyer under this Agreement in an interest-bearing escrow account until a cure has been achieved. Once the Event of Default has been cured, the Supplier must pay any outstanding payments owed to the Buyer and the Buyer must pay the Supplier any outstanding

payments owed to the Supplier, whichever the case may be.

(c) If an uncured Event of Default of Buyer shall have occurred and be continuing, and the MDPSC has not affected a cure pursuant to Section 8.5(b) within the allotted cure period, the Supplier shall have the right to seek any of the following remedies (or combinations thereof):

1. Designate an "Early Termination Date" pursuant to Section 8.6;
2. Withhold any payments due to the Buyer under this Agreement;
3. Suspend performance under this Agreement; and/or,
4. Exercise any remedy available at Law, in equity, or under this Agreement to the extent an Event of Default has not been timely cured by the Buyer.

(d) If the Event of Default by Buyer is the voluntary or involuntary filing of a petition commencing a case under the Bankruptcy Code, then the Supplier shall have the right to terminate this Agreement by notice to the Buyer and such termination shall take effect immediately upon issuance of such notice by the Supplier to the Buyer. The Supplier shall have the right to damages (if any) calculated pursuant to 11 U.S.0 § 562, as it may be amended from time to time, and other applicable Law. The Parties agree that each is a Financial Participant for the purposes of the Bankruptcy Code and waive any right to contest the other's status as a

Financial Participant in any proceeding under the Bankruptcy Code. The Early Termination Payment, as described in Section 8.7, will not apply in this instance.

8.6 Notice and Declaration of an Early Termination Date

If an Event of Default as set forth in Section 8.1 or Section 8.4, has occurred and is continuing, and any relevant cure period pursuant to Section 8.1 or Section 8.4 has expired, the non-defaulting Party (the "Non-Defaulting Party") shall have the right (i) to notify the defaulting Party (the "Defaulting Party") and to designate a day, no earlier than the effective date of such notice and no later than twenty (20) calendar days after such notice is effective as an early termination date (the "Early Termination Date"); (ii) to request and obtain payment from the Defaulting Party of the Early Termination Payment calculated pursuant to Section 8.7 hereof plus all amounts owed by the Defaulting Party to the Non-Defaulting Party for performance or non-performance that occurred, arose or accrued prior to the Early Termination Date; and, (iii) to terminate the Agreement between the Parties as of the Early Termination Date.

8.7 Calculation of Early Termination Payment

(a) For all Events of Default other than Bankruptcy, as described in Sections 8.2(b) and Section 8.5(d)., the Non-Defaulting Party shall calculate, in a commercially reasonable manner, an "Early Termination Payment" which will be based on the following "Settlement Amount":

1. The "Settlement Amount" will be equal to the Losses or Gains, and Costs, expressed in U.S. Dollars, which such Party incurs as a

result of the liquidation of this Agreement, pursuant to Section 8.6.

i. "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of this Agreement, determined in a commercially reasonable manner.

ii. "Gains" means, with respect to any party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of this Agreement, determined in a commercially reasonable manner.

iii. "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged it obligations or entering into new arrangements which replace this Agreement; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of this Agreement.

2. The Gains and Losses for this Agreement shall be determined by calculating the amount that would be incurred or realized to replace or to provide the economic equivalent of the remaining payments or deliveries in respect to this Agreement. The non-Defaulting Party (or its agent) may

determine its Gains and Losses by reference to information either available to it internally or supplied by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, in information vendors and other sources of market information. The non-Defaulting Party shall provide all data used to determine its Gains and Losses, including but not limited to price curves to the Defaulting Party.

3. The discount rate to be used in the calculation of the Early Termination Payment shall be equal to the discount rate used by the MDPSC to evaluate offers in the competitive solicitation process that resulted in this Agreement.

(b) The Parties must pay one another any outstanding amounts owed.

(c) The Parties further agree that, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party from the Defaulting Party pursuant to Article 10 of this Agreement shall be withdrawn, drawn on, or otherwise collected or netted against the Early Termination Payment and retained by the Non-Defaulting Party.

(d) As soon as practicable after such termination and receipt of security, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the Early Termination Payment. The notice shall include a written statement explaining in reasonable detail the calculation of such payment amount. Any amount by which the Early Termination Payment exceeds the funds already received shall be paid by the Defaulting Party if it owes any excess within five (5) Business Days after such notice is effective.

(e) Each Party acknowledges and agrees with respect to the liquidated damages in this section that:

1. the actual damage expected as a result of the Defaulting Party's breach of these requirements would be substantial;
2. both Parties intend that the Defaulting Party would pay the specified liquidated damages amount for such a breach;
3. this amount of damages is not a penalty;
4. the amount of damages is reasonable in the sense that it is not disproportionate to the damages the Parties expect that the Non-Defaulting Party would sustain if the Defaulting Party breaches this provision;
5. the amount of liquidated damages is a genuine pre-estimate of the loss that the Non-Defaulting Party will incur; and
6. such liquidated damages shall be the sole damages to which the Non-Defaulting Party

shall be entitled as a result of the Defaulting Party's breach of these requirements.

ARTICLE 9

FORCE MAJEURE; LIMITATION ON LIABILITY

9.1 Force Majeure

Each Party shall be excused from performing its respective obligations under this Agreement and shall not be liable in damages or otherwise to the Non-Claiming Party if and to the extent that the MDPSC finds that the Claiming Party is unable to so perform or is prevented from performing its obligations by an event of Force Majeure.

9.2 Limitation on remedies for Force Majeure

(a) If the MDPSC finds that either Party is rendered wholly or partly unable to perform its obligations hereunder because of Force Majeure, then that Party shall be excused from performance of its obligations to the extent that such performance is affected by the Force Majeure, provided that:

1. The Claiming Party shall, as soon as practicable after the occurrence of Force Majeure, give the MDPSC and the Non-Claiming Party written notice describing the particulars of the occurrence and requesting that the MDPSC make a determination within 15 days on the issue of whether the occurrence constitutes a Force Majeure event that excuses performance;

2. The suspension of performance shall be of no greater scope and of no longer duration than is reasonably required by the Force Majeure;

3. The Claiming Party uses all commercially reasonable efforts to remedy its inability to perform; and,

4. Nothing in this Section 9.2 shall affect a Party's obligation to make payments when due or becoming due with respect to performance or non-performance prior to the event of Force Majeure.

(b) While an event of Force Majeure is in effect, the Claiming Party shall take all commercially reasonable steps to mitigate the effects of Force Majeure, shall info'in the Non-Claiming Party in writing on a weekly basis of when it expects to remove the cause of Force Majeure and what steps it is taking to cure or eliminate the event of Force Majeure.

(c) If an event of Force Majeure causes the Supplier to not achieve a Milestone Event by the relevant Milestone Date, or to not achieve Commercial Operation on or before the Milestone Date for Commercial Operation, as applicable, then such Milestone Date shall be extended for a period of time equal to the period of delay resulting from such Force Majeure event.

(d) If an event of Force Majeure described in Section 9.2(c) has delayed the Commercial Operation Date of the Facility by more than eighteen (18) months after the original Milestone Date (prior to any extension pursuant to Section 9.2(c)) set out for attaining Commercial Operation of the Facility, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, the

Buyer, with the MDPSC's approval, may terminate this Agreement upon written notice to the Supplier, and, thirty (30) calendar days after the effective date of notice, this Agreement shall automatically terminate and without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(e) If, by reason of Force Majeure, the Supplier is unable to perform or comply with its obligations (other than payment obligations) hereunder after the Commercial Operation Date for more than eighteen (18) months, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, then the Buyer, with the MDPSC's approval, may terminate this Agreement upon thirty (30) calendar days' written notice to the Supplier, and thirty (30) calendar days after the effective date of the said written notice, this Agreement shall automatically terminate without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(f) If the Buyer is the Claiming Party and the Buyer is unable to perform or comply with its obligations hereunder after the Commercial Operation Date for more than eighteen (18) months, then notwithstanding anything in this Agreement to the contrary, while the delay that is a result of the event of Force Majeure is continuing, then the Supplier may terminate this Agreement upon thirty (30) calendar days' written notice to the Buyer, and thirty (30)

calendar days after the effective date of the said written notice, this Agreement shall automatically terminate without any costs or payments of any kind to either Party, and the Completion and Performance Security shall be returned forthwith.

(h) After the Term Commencement Date, an event of Force Majeure shall not extend the Term of this Agreement.

9.3 Liability and Damages

Except as provided for under this Agreement, neither Party shall be liable under this Agreement for any special, indirect, incidental, consequential, or punitive damages of any kind, including but not limited to loss of use, out of pocket expenses, and lost profits (past or future), by statute, in tort or contract, or otherwise.

ARTICLE 10

CREDIT AND SECURITY REQUIREMENTS

10.1 Completion and Performance Security Amount

The Supplier shall provide security to the Buyer on the Effective Date of this Agreement for the performance of the Supplier's obligations under this Agreement, in the applicable amount as set out in Section 10.1 below and in the form described in Section 10.2 (the "Composition of the Completion and Performance Security").

(a) The amount of the Completion and Performance Security applicable prior to the Facility's Commercial Operation Date shall be set at U.S. Dollar 100 per kW of the Facility's UCAP Upon the Facility's Commercial Operation Date, the

Completion and Performance Security shall be set at U.S. Dollar 50 per kW of the Facility's UCAP.

For fixed price fuel offers only, at the beginning of each Contract Year, the simple average of the Henry Hub Spot Price over the previous Contract Year will be compared to the fixed fuel price offered for the previous Contract Year. If the average Henry Hub Spot Price is 125% or greater than the fixed fuel price, the Buyer retains the right to request additional Completion and Performance Security. The amount of the additional Completion and Performance Security will be up to $50 per kW. The additional Completion and Performance Security will be returned to the Supplier a) when the term of the fixed fuel price offer has expired, or b) when the annual comparison is performed and the average Henry Hub Spot Price is less than 125% of the fixed fuel price.

(b) Effective 365 days after the Facility's Commercial Operation Date and on each yearly anniversary thereafter, and provided that the Buyer has determined that any liquidated damages payable by the Supplier under Article 2 have been paid in full by the Supplier, then the amount of the Completion and Performance Security shall be reduced by an amount equal to the product of (i) U.S. Dollar 50 per kW of UCAP and (ii) 1/Term, for the remaining Term of this Agreement.

(c) In the event that the Buyer, in accordance with this Agreement, has recovered monies that were due to it using all or part of the Completion and Performance Security, the Supplier shall

within a commercially reasonable time, not to exceed three (3) Business Days, provide replacement security to cover an amount equal to that recovered or paid out of the Completion and Performance Security.

(d) Not maintaining the Completion and Performance Security at its full amount shall be an Event of Default with a three (3) Business Day cure period, pursuant to Section 8.1.

(e) The Supplier shall provide to the MDPSC and the Buyer reasonable evidence of any security that it posts for the same Original Contract Quantity to participate in the RPM before the Facility reaches Commercial Operation. The amount of security provided to PJM may be used to reduce the Completion and Performance Security required under this Agreement as long as the security provided to PJM is not in the form of a guarantee, such that the total security provided by the Supplier to the Buyer and to PJM for the purpose of Confirmed Contract Quantity participating in the RPM totals the Completion and Performance Security calculated pursuant to this Section 10.1.

(f) The Buyer shall return the Completion and Performance Security to the Supplier with accrued interest (if relevant) on the first Business Day following the last calendar day of the Term of this Agreement (or, if relevant, on the first Business Day after the Early Termination Date), provided that the Buyer has determined that the Supplier has paid in full any outstanding liquidated damages or Early Termination Payments.

10.2 Composition of Completion and Performance Security

(a) The Completion and Performance Security shall be provided in the form of either (i) cash, which will be held in an interest-bearing Escrow account by a Qualified Institution selected by the Buyer for the benefit of the Buyer; (ii) a Letter of Credit; (iii) a performance bond; (iv) a certified check made payable to Buyer; (v) a bank draft made payable to Buyer; or (vi) other equivalent form of security acceptable to the Buyer acting reasonably, and subject to the approval of the MDPSC, but for certainty, shall not include guarantees. The Completion and Performance Security can also be composed of a mix of such instruments so long as the total amount required under Section 10.1 of this Agreement is achieved. The MDPSC's determination under this Section 10.2(a) is not subject to the dispute resolution guidelines listed in Section 12.9.

(b) Costs of the Completion and Performance Security shall be borne by the Supplier.

(c) If cash is provided by the Supplier for the Completion and Performance Security, such cash will be held in an interest-bearing Escrow account by the Buyer in a Qualified Institution. The interest accrued in this Escrow account will be paid to the Supplier upon the Term Termination Date as long as there are no outstanding disputes between the Parties.

(d) If a Letter of Credit is used:

1. The bank providing the Letter of Credit must be a Qualified Institution, or be

otherwise submitted to the MDPSC for approval.

2. Within two (2) Business Days of the Effective Date, Supplier shall provide to Buyer a Letter of Credit in the amount of $ [_____] to secure Supplier's performance from the Effective Date until either expiration of this Letter of Credit or the Termination Date. The Letter of Credit shall have a term of not less than one (1) year and an evergreen clause acceptable to the Buyer and the MDPSC. The Letter of Credit shall provide that if this Agreement remains in effect and the Letter of Credit is due to expire, Buyer shall have the right to draw on the full amount of such Letter of Credit. In that event, Buyer will hold such funds until Supplier has provided Buyer with a replacement Letter of Credit or other form of security that meets the requirements of this Article 10 of this Agreement.

3. If the Credit Rating of the Qualified Institution providing the Letter of Credit falls below the levels specified in the definition of a Qualified Institution, the Supplier shall have five (5) Business Days following written notice by the Buyer to obtain a suitable Letter of Credit from another Qualified Institution, unless the Buyer agrees in writing to extend such cure period.

(e) If a performance bond is used:

1. The performance bond must allow the Buyer, acting reasonably, to determine

whether the surety will pay or perform the Defaulting Party's obligations.

2. The performance bond must require the surety to pay all undisputed amounts requested in writing by the Buyer within five (5) Business Days, and must deposit any disputed amounts into an Escrow account for the benefit of the Buyer pending resolution of the dispute between the Buyer and the surety. Any interest accrued in the Escrow account must be paid to the Buyer or the surety on a pro rata basis depending on how the issue is resolved.

3. The performance bond must be irrevocable, and must remain in place for the entire Term of this Agreement.

4. The surety must agree to (i) waive notice of any alteration or extension of time provided by either Party under this Agreement; (ii) waive notice of any amendment to this Agreement; (iii) following the occurrence of an uncured Event of Default by the Supplier, waive any requirement under applicable Law or otherwise that Buyer first proceed against (and obtain judgment against) the Supplier before Buyer can enforce its rights under the performance bond against the surety.

5. In the event that Buyer prevails in its attempts to enforce its rights under the performance bond, the surety must agree to pay for all the documented legal costs, fees, and expenses Buyer incurred in the enforcement action.

6. The performance bond must be governed by and enforced in accordance with the Laws of the State of Maryland; and any proceeding under the Performance Bond must be instituted in a court of competent jurisdiction in Maryland.

ARTICLE 11

CONTRACT ADMINISTRATION

11.1 Inspection and Audit

Each Party and the MDPSC has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. The Contract will be purely between the Supplier and Buyer(s), subject to approval of recovery from the MDPSC. If requested, the Supplier shall provide to the Buyer and the MDPSC and/or its staff statements evidencing the performance of its obligations. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the interest rate (as defined in Section 6.4) from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twenty-four (24) months from the rendition thereof, and thereafter any objection shall be deemed waived.

11.2 Notices

(a) Any notice, demand, or request permitted or required under this Agreement shall be

delivered in person, by prepaid overnight United States mail or by overnight courier service, return receipt requested, to a Party at the applicable address set forth below:

To Buyer:
Name or Title:
Company:
Full Address:
City, State, Zip
Telephone:

To Supplier:
Name or Title:
Company:
Full Address:
City, State, Zip
Telephone:

To MDPSC:
David J. Collins
Executive Secretary
6 St. Paul Street
Baltimore, MD 21202
Tel: 410-767-8068

(b) Notices by hand delivery or facsimile (provided a copy is also sent by overnight mail) shall be effective at the close of business on the day actually sent, if sent during sending Party's business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day.

(c) The addresses for notice specified in Section 11.2(a) may be changed from time to time by written notice by any Party or the MDPSC to all other Parties and the MDPSC without amendment of this Agreement.

11.3 Records and Billing Verification Rights

(a) The Supplier and the Buyer each shall keep complete and accurate records with respect to its performance under this Agreement and shall maintain such records for a period of five (5) years after final billing for verification by the other Party and the MDPSC. In the event of any billing dispute, all such records pertaining to the dispute shall be maintained until such later time as the billing dispute is resolved. If a billing dispute establishes that any bill submitted to and paid by the Buyer was for an amount greater than properly chargeable under this Agreement, the Supplier shall refund to the Buyer the excess amount collected together with interest calculated from the date of payment to the refund date in accordance with the regulations of FERC applicable to the payment of interest on refunds. If a billing dispute establishes that any bill submitted to and paid by the Buyer was for an amount less than properly chargeable under this Agreement, the Buyer shall make such additional payment to the Supplier, together with interest calculated from the due date to the date of payment in accordance with regulations of FERC applicable to the payment of interest on refunds.

(b) In the event of a good faith dispute regarding any bill issued or payment due under this Agreement, each Party shall have the right to verify the accuracy or the calculation of the bill, at its own expense, to obtain copies of relevant portions of the books or records of the other Party insofar as may be necessary for the

purpose of ascertaining the accuracy of any invoice or calculation of payment due. Each Party supplying information hereunder may require that the other Party maintain the confidentiality of such information in accordance with Section 12.10. The Parties agree to individually and jointly request from PJM, or other appropriate source, any data or information that either Party believes is reasonably necessary for purposes of a requested accounting or resolution of a billing dispute.

ARTICLE 12

MISCELLANEOUS

12.1 Change of Control, Sale of Facility, or Assignment

(a) Except as part of a collateral assignment or stock pledge in favor of the Financing Parties, no direct or indirect change of control of the Supplier shall be allowed without the MDPSC s approval pursuant to Title 6-105 of the PUA. By entering into this Agreement, the Supplier agrees to submit to the jurisdiction of the MDPSC for purposes of Title 6-105 of the PUA and to comply with the provisions of that article. The successor entity must assume all responsibilities and obligations of the Supplier under this Agreement and must sufficiently demonstrate to the MDPSC that it has the technical, managerial, arid financial wherewithal to serve as the Supplier for the remainder of the Term and that the transaction meets the requirements of Title 6-105(g)(3).

(b) The Buyer may assign, pledge or transfer this Agreement to a successor electric company, subject to MDPSC approval.

(c) This Agreement shall be binding upon, and shall inure to the benefit of, and shall be performed by, each permitted successor and assignee of the Parties, except that no assignment, pledge or transfer of this Agreement by either Party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement unless the MDPSC approves the assignment, pledge or other transfer and expressly releases the assignor, pledgor, or transferor from its obligations hereunder.

(d) The Buyer agrees that (i) the Supplier may assign, mortgage, hypothecate, pledge or otherwise encumber, by way of security or collateral, all or any portion of the Supplier's interest in and to this Agreement in favor of any Financing Party and its successors and assigns and (ii) any such Financing Party may assign such interest in and to this Agreement to any subsequent assignee that is also a Financing Party in connection with the sale, transfer, or exchange of its rights under this Agreement. Any such Financing Party may operate the Facility pursuant to such assignment upon and after the exercise of such Financing Party's rights and enforcement of its remedies against the Supplier or the Facility under any deed of trust or other security instrument, creating a lien in its favor, in each case with notice to, but without the consent of, the Buyer, provided that the Supplier has demonstrated to the satisfaction of

the MDPSC that any such Financing Party (or the security agent acting on behalf of all the Financing Parties, where there are more than one) or its designee or transferee has entered into an agreement with the Buyer under which each Financing Party or its designee or transferee agrees to be fully bound by all the terms and conditions of this Agreement as if it had been substituted by the Supplier. In order for a collateral assignment to occur as contemplated in this Section 12.1(d), there must be a single entity designated as trustee on behalf of all Financing Parties and the trustee or agent, on behalf of all Financing Parties, must agree to comply with all provisions in this Section 12.1.

12.2 Notice of Deterioration of Financial Indicators

The Parties shall provide notice to the MDPSC and each other of any deterioration of any of their respective Credit Ratings, or any other financial indicators agreed upon in writing between the Buyer and the Supplier at the Execution Date. If the Supplier is not a publicly rated entity, then the Supplier shall provide written notice to the MDPSC and the Buyer of any material deterioration in the Supplier's financial condition immediately upon becoming aware of such deterioration.

12.3 Subcontracting

The Supplier may subcontract its duties or obligations under this Agreement without the prior written approval of MDPSC or the Buyer, provided that no such subcontract shall relieve the Supplier of liability for performing any of its duties and obligations hereunder.

12.4 Taxes

(a) Each Party shall be responsible for all federal, state, and local Taxes incurred by it as a result of entering into this Agreement; provided, however, that the Supplier shall be responsible for all Taxes imposed on, or assessed to, the Facility and the Site, all payments obtained by the Supplier pursuant to this Agreement and all payments obtained by the Supplier resulting from participation in any of the PJM Markets.

(b) Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all Taxes, so long as neither Party is materially adversely affected by such efforts.

12.5 Governing Law

(a) The Parties agree that any and all disputes and issues regarding this Agreement must be brought first to the MDPSC for resolution. The Parties waive any right to present any disputes or issues in any other forums except as provided in the Maryland Annotated Code, State Government Article, Section 10-101 et seq.

(b) The interpretation and performance of this Agreement shall be governed by the Laws of the State of Maryland without resort to any conflicts of laws principles that will result in the applications of Laws other than the Laws of the State of Maryland.

(c) To the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby also expressly and irrevocably

waives any rights it can or may have, now or in the future, whether under Sections 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC, or to support another in obtaining, by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, or support another in obtaining, an order from FERC changing any section of this Agreement specifying the pricing, charges, classifications or other economic terms and conditions agreed to by the Parties. In the event it were to be finally determined that applicable law precludes one or both Pa_Vies from waiving its rights to seek changes from FERC to this Agreement (including entering into covenants not to do so) then this section shall not apply, provided that neither Party shall seek any such changes except under the "public interest" standard of review as set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956 (the "Mobile-Sierra" Doctrine.)

12.6 Relationship of Parties

The Parties acknowledge that as between the Supplier and the Buyer there is an independent contractor relationship, and that nothing in this Agreement shall create any joint venture, partnership, or principal/agent relationship between the Parties. Neither Supplier nor Buyer shall have any right, power, or authority to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

12.7 Complete and Full Agreement; Amendments; Severability; Waiver

(a) This Agreement (including the Exhibits, Schedules and any written supplements hereto) and the MDPSC's decisions and orders relating hereto constitute the entire agreement between the Parties relating to the subject matter of this agreement.

(b) This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Agreement shall be enforceable unless reduced to writing, approved by the MDPSC, and executed by both Parties.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the other provisions hereof. If any provision of this Agreement is held to be invalid, such provision shall not be severed from this Agreement; instead, the scope of the rights and duties created thereby shall be reduced by the smallest extent necessary to conform such provision to the applicable Law, preserving to the greatest extent the intent of the Parties to create such rights and duties as set out herein. If necessary to preserve the intent of the Parties hereto and the prevailing economic balance between the Buyer and the Supplier at the Execution Date, the Parties shall negotiate in good faith to amend this Agreement, adopting a substitute

provision that is legally binding and enforceable for the one deemed invalid or unenforceable.

(d) Any number of counterparts of this Agreement may be executed and each shall have the same force and effect as the original, but all of which shall together constitute one and the same instrument.

(e) The captions to Articles and Sections throughout this Agreement are intended solely to facilitate reading and reference to all Articles, Sections and provisions of this Agreement. Such captions shall not affect the meaning or interpretation of this Agreement.

(f) Except as provided in Article 6.4(d) and 11.1 of this Agreement, a Party's failure to timely enforce compliance with any term or provision of this Agreement shall not be deemed to be a waiver of any said Party's rights under this Agreement.

12.8 Indemnification

(a) General. Each Party (each, an "Indemnifying Party") shall indemnify, defend and hold harmless the other Party, its parents and affiliates and its and their respective officers, directors, lenders, trustees, employees, contractors, subcontractors, and agents (each an "Indemnified Party"), from and against any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorneys' fees, and all other obligations by or to third parties arising out of or resulting from the Indemnifying Party's (including its affiliates'

officers', directors', lenders', trustees', employees', contractors' and subcontractors', and agents') negligence or actions or omissions under, in connection with, or arising out of, this Agreement; provided , however, that the Indemnifying Party shall not be liable for damages or losses arising out of gross negligence or intentional misconduct by the Indemnified Party, its affiliates and its and their respective officers, directors, lenders, trustees, employees, contractors, subcontractors, or agents.

(b) Indemnification Procedures. A Party seeking indemnification from another Party under this Section 12.8 shall give the other Party notice of such claim as soon as reasonably practical after the commencement of or actual knowledge of such claim or action. Such notice shall describe the claim in reasonable detail, and shall indicate the amount (estimated if necessary) of the claim that has been or may be asserted against or sustained by such Party. To the extent that the other Party is reasonably determined to be materially prejudiced as a result of failure to provide such notice, such notice shall be a condition precedent to liability of the other Party under the indemnification provisions of this Agreement. Neither Party may settle or compromise any claim for which indemnification is sought without the prior written consent of the other Party, provided, however, such consent shall not he unreasonably withheld, delayed or conditioned. The indemnification obligations of each Party shall continue in full force and effect regardless of whether this Agreement has expired or

terminated, and shall not be limited in any way by any limitation on insurance, on the amount or types of damages (including any such limitations on damages set forth in this Agreement), or by any compensation or benefits payable by the Parties under worker's compensation acts, disability benefit acts or other employee acts.

12.9 Dispute Resolution

Except as otherwise expressly set forth herein, for any and all disputed issues, the Parties shall refer to this Section 12.9. A Party must respond to the other Party's notice concerning a disputed issue within ten (10) Business Days of first notification unless otherwise specified in this Agreement.

(a) Negotiation between Executives. The Parties shall attempt in good faith to resolve any dispute arising out of or relating to this Agreement promptly by negotiation between executives who have authority to settle the controversy and who are at a higher level of management than the persons with direct responsibility for administration of this Agreement. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business ("Initial Notice"). A copy of the Initial Notice shall also be given to the MDPSC. Such Initial Notice shall include: (a) a statement of that Party's position and a summary of arguments supporting that position; and (b) the name and title of the executive or counsel who will be negotiating on behalf of that Party and of any other person who will accompany the executive. Within five (5) Business Days after the effective date of the Initial Notice, the receiving Party shall respond

with: (a) a statement of that Party's position and a summary of arguments supporting that position; and (b) the name and title of the executive or counsel who will negotiate on behalf of that Party and of any other person who will accompany the executive. Within fifteen (15) Business Days after delivery of the Initial Notice, the executives or counsels of both Parties and a representative from the MDPSC shall meet at a mutually acceptable time and place, and thereafter as often as they reasonably deem necessary, to attempt to resolve the dispute. All reasonable requests for information made by one Party to the other will be honored. All negotiations pursuant to this clause are confidential and shall be treated as compromise and settlement negotiations for purposes of applicable rules of evidence. If the Parties are unable to resolve the dispute within sixty (60) Business Days after the delivery of the initial Notice, a Party may petition the MDPSC to initiate a proceeding to resolve the dispute. The Parties should report to the MDPSC any resolution of disputes agreed to by the Parties within five (5) Business Days of said agreement.

(b) The Parties agree that all disputes or issues arising out of this Agreement shall be brought first to the MPDSC for resolution of the dispute or issues. The Parties waive their right to bring disputes or issues to any other forum except as provided in the Md. Ann. Code, SG Section 10-101 et seq. To the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby also expressly and irrevocably waives any rights it can or may have, now or in the future, whether under

Section 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC, or to support another in obtaining, by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, or support another in obtaining, an order from FERC changing any section of this Agreement specifying the pricing, charges, classifications or other economic terms and conditions agreed to by the Parties. In the event it were to be finally determined that applicable law precludes one or both Parties from waiving its rights to seek changes from FERC to this Agreement (including entering into covenants not to do so) then this Section shall not apply, provided that neither Party shall seek any such changes except under the "public interest" standard of review as set forth in the Mobile-Sierra Doctrine.

12.10 Confidentiality

In accordance with the terms of the Confidentiality/ Non-disclosure Agreement (Appendix 11 of the Request for Proposals For Generation Capacity Resources Under Long-term Contract:)

(a) The contents of this Contract Agreement and all other documents relating to the Contract Agreement and any information made available by a Party ("Disclosing Party") to the other Party ("Non-Disclosing Party") with respect to this Agreement are presumed to be public, unless the MDPSC has granted a request for confidential treatment pursuant to Section 12.10(b). To obtain confidential treatment, Parties should file information that they seek to

treat as confidential under seal along with a motion for a protective order requesting that the MDPSC grant confidential treatment for specific data or information that they deem to be proprietary and confidential. The information filed under seal should clearly be marked "confidential" on the top of each page. The motion should indicate the basis in federal or state law for keeping the information confidential.

(b) Parties requesting confidential treatment from the MDPSC must clearly specify exactly which information they seek to treat as confidential, for how long such confidential treatment shall last, and whether or not the information for which confidential treatment is being sought will be provided on a regular basis and whether it shall be protected each time. Once the MDPSC has ruled that such information is confidential, the ruling will he valid for the duration of the Term of this Agreement, unless such information has become non-confidential according to Section 12.10(c) of this Agreement.

(c) All information is automatically non-confidential if such information (i) has become generally available to the public other than as a result of a disclosure by the Non- Disclosing Party or its Representatives, or (ii) may be obtained from a non-confidential source that disclosed such information in a manner that is not known by the Non- Disclosing Party to have violated such entity's obligations to the Disclosing Party, if any, in making such disclosure.

(d) In addition, confidentiality status of information does not preclude it from being released

to a third party (i) as may be required in response to any summons or subpoena from a regulatory body, or otherwise required in connection with any litigation or to comply with any applicable Law, order, regulation, ruling, regulatory request, accounting disclosure rule or standard or any exchange, control area or independent system operator rule (provided that the Non-Disclosing Party shall promptly and in advance, in possible, notify the Disclosing Party of the requested disclosure so that Disclosing Party may seek a protective order or other appropriate remedy, or, in its sole discretion, waive compliance with the terms of this Section 12.10), or (ii) being furnished to the Non-Disclosing Party's Affiliates, and to the Non-Disclosing party's auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees (collectively, "Representatives") who were not entering into or performing under this Agreement; provided, however, that any Representatives to whom the Non-Disclosing Party discloses the information shall be required to observe the terms of this Section 12.10.

12.11 MDPSC Options to Extend Contract

(a) The MDPSC can at any time three hundred and sixty-five days before the end of the year term of this Agreement notify the Supplier and Buyer in writing that the MDPSC elects to extend this Agreement for a term not to exceed ten years unless the Supplier consents to a longer term.

(b) The Buyer shall notify the MDPSC in writing seven hundred and thirty days before the end of the year term that the MDPSC has three

hundred and sixty five days to exercise the option afforded under Section 12.11(a)

(c) All of the terms and conditions of this Agreement will apply to any extended contract term.

(d) If the MDPSC extends the term of this Agreement, the Supplier must submit pricing terms. The Supplier can also propose amendments to the Agreement as part of its new pricing proposal for the extended contract term.

12.12 Environmental Changes in Law

(a) Supplier hereby represents and warrants that the design and operation in accordance with this Agreement of the Facility is and shall be in material compliance with all applicable laws (including but not limited to the Clean Air Act Amendments of 1990 and all implementing rules, regulations, orders and mandatory standards of any Governmental Authority related thereto) and all Governmental Approvals applicable to Supplier or the Facility, whether or not such Governmental Approvals have been obtained, related to the stack emissions by the Facility into the air, as a result of the combustion of fuel in the normal course of operation, of any substance, material, gas, or particulate matter that is regulated by any Governmental Authority ("Applicable Air Permits and Laws"), which were in effect or reasonably anticipated as of the Effective Date.

(b) Notwithstanding anything in this Section 12.12 (Environmental Changes- in-Law) above to the contrary, the Buyer shall have the right to terminate this agreement if any adjustment in the anticipated payments related to a Change-

in-Law affecting Applicable Air Permits and Laws would cause Buyer's anticipated payments to Supplier under this Agreement to be increased by more than ten percent (10%) of Buyer's then-current payment amount or should the total accumulation of all such adjustments cause Buyer's payments to Supplier under this Agreement to be increased in total by more than an amount equal to twenty percent (20%) of Buyer's then-current payment amount. If Buyer terminates this Agreement as provided in the prior sentence, Supplier may nullify such termination by either (1) providing written notice to Buyer within thirty (30) days following receipt of Buyer's termination notice that Supplier permanently waives its right to the amount of any such adjustment which is in excess of the limits described above, or (2) obtaining a final and non-appealable order from the MDPSC within one hundred eighty (180) days following receipt of Buyer's termination notice determining that such costs are prudent and necessary and approving the timely and complete recovery of the increased costs in Buyer's MDPSC jurisdictional rates to the satisfaction of the Buyer. If requested by Supplier in writing, Buyer will use commercially reasonable efforts, at Supplier's sole cost and expense, to obtain such order from the MDPSC, but shall have no obligation to appeal or otherwise contest any decision of the MDPSC. Supplier will reimburse Buyer for such costs and expenses as they are incurred by Buyer, promptly upon Buyer's written demand. Supplier agrees to be bound by the decision of the MDPSC (subject to the normal rules for appeal

of the decision of the MDPSC by Supplier) and waives all claims concerning this issue before FERC.

IN WITNESS WHEREOF, the undersigned Parties have caused this Agreement to be executed in their names by their respective duly authorized officials.

[Corporate Name of Buyer]
By:_____
[Buyer Representative's Name] [Buyer Representative's Title]
[Corporate Name of Supplier]

By:_____
[Supplier Representative's Name]
[Supplier Representative's Title]

ARTICLE 13

EXHIBITS

The MDPSC reserves the right to add additional information to the Exhibits from the Supplier's Proposal at the time of selection of winning projects.

13.1 Exhibit A: Facility Description and Site Map

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process, supplemented from time to time with revised data as permitted required in this Agreement. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

Legal name of supplier:

Summer capacity (MW):

Winter capacity (MW):

Description of facility location:

U.S. Geological Survey (USGS) scale map showing Facility Location:

Facility site layout drawing:

Facility water process mass balance drawing:

Facility heat process mass balance drawing:

Facility piping and instrumentation drawing:

Facility electrical one-line diagram:

Facility control relay, telemetry, Supervisory Control and Data Acquisition (SCADA), Generating Availability Data System (GADS), telecommunications and protective relay equipment drawing(s):

Facility fire protection system drawing:

Type of generator:

Generator busbar voltage:

Generator excitation system:

Generator cooling system description:

Generator capacity:

Standard summer generator capacity:

Emergency short duration summer generator capacity:

Standard winter generator capacity:

Emergency short duration winter generator capacity:

Description of key equipment:

Description of electric generator(s) and generator ancillary equipment:

Description of steam process major equipment (if any):

Description of fuel handling equipment major components:

Description of Generator Step Up (GSU) Transformer(s)

Description of GSU cooling system:

GSU interconnection "high side" voltage:

Manufacturer of GSU transformer(s):

Capacity of each GSU transformer

Summer normal:

Summer emergency short duration:

Winter normal:

Winter emergency short duration:

Quantity of GSU transformers to be installed:

Description of major balance of plant components (as applicable):

Air preparation, separation and handling equipment:

Water purification system:

Bus bar and switchgear components:

Facility control system (including software and hardware components):

Steam process equipment, including boilers:

Plant cooling system:

Telecommunications, telemetry, SCADA and GADS systems:

Solid fuel handling, conditioning and delivery system:

Solid fuel storage facility:

Liquid fuel handling, conditioning and delivery system:

Liquid fuel storage facility:

Gas fuel handling, conditioning and delivery system:

Gas fuel storage facility:

Waste (includes ash and combustion solids) disposal and handling system:

Air quality emission monitoring system:

Electrical interconnection:

Description of the point of interconnection:

Interconnection voltage:

Electrical one-line diagram of interconnection:

Physical layout drawing of the interconnection:

13.2 Exhibit B: Milestone Events and Milestone Dates for the Facility

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

Note that starred Milestone Events represent Key Milestone Events for the purpose of this Agreement.

Milestone Event Milestone Date Permanent site control achieved*

Major permits applied for, including PJM

Interconnection study, Siting Authorities, Environmental, and other studies as applicable.

Major permits obtained, including receipt of approvals from the PJM, MDPSC, and FERC, as applicable

Engineering, equipment procurement, and construction contract(s) executed

Financial closing*

Interconnection study completed

Equipment ordered

Major equipment delivered

Commencement of construction*

Foundations laid

Interconnection completed

Completion of major construction - ready for testing

Commercial operation*

13.3 Exhibit C: Design Parameters of the Facility and Performance Benchmarks

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process, supplemented from time to time with revised data as permitted required in this Agreement. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

UNIT CHARACTERISTICS

[NAME]

Unit configuration (i.e., combined cycle, single cycle, etc.) Manufacturer and unit class (i.e., GE Frame H, etc.)

Primary fuel_____

Secondary fuel:_____

Low Operating Limit:_____

High Operating Limit (normal):_____

High Operating Limit (emergency):_____ MW

Ramp Rate (normal):_____MW/Minute

Ramp Rate (emergency):_____MW/ Minute

Minimum Run Time:_____hours (_ days)

Minimum Shutdown Time:_____hours

Start Up Time (Cold Conditions)*:_____hours

Start Up Time (Hot Conditions):_____hours

*Cold start applies after_____hours from shutdown

Automatic Generation Control (AGC) Equipment (Yes/No)?

Contract Annual Heat Rate. This table must match the Contract Annual Heat Rate table provided in Attachment 7 Part B for the purposes of contract energy price calculation:

June 1, 2015	to May 31, 2016	Btu/kWh
June 1, 2016	to May 31, 2017	Btu/kWh
June 1, 2017	to May 31, 2018	Btu/kWh
June 1, 2018	to May 31, 2019	Btu/kWh
June 1, 2019	to May 31, 2020	Btu/kWh
June 1, 2020	to May 31, 2021	Btu/kWh
June 1, 2021	to May 31, 2022	Btu/kWh
June 1, 2022	to May 31, 2023	Btu/kWh

June 1, 2023	to May 31, 2024	Btu/kWh
June 1, 2024	to May 31, 2025	Btu/kWh
June 1, 2025	to May 31, 2026	Btu/kWh
June 1, 2026	to May 31, 2027	Btu/kWh
June 1, 2027	to May 31, 2028	Btu/kWh
June 1, 2028	to May 31, 2029	Btu/kWh
June 1, 2029	to May 31, 2030	Btu/kWh
June 1, 2030	to May 31, 2031	Btu/kWh
June 1, 2031	to May 31, 2032	Btu/kWh
June 1, 2032	to May 31, 2033	Btu/kWh
June 1, 2033	to May 31, 2034	Btu/kWh
June 1, 2034	to May 31, 2035	Btu/kWh
June 1, 2035	to May 31, 2036	Btu/kWh
June 1, 2036	to May 31, 2037	Btu/kWh
June 1, 2037	to May 31, 2038	Btu/kWh
June 1, 2038	to May 31, 2039	Btu/kWh

Contract Target Availability. This table must match the Contract Target Availability table provided in Attachment 7 Part A for the purposes of calculating Availability Bonus or Deficiency.

June 1, 2015	to May 31, 2016	%
June 1, 2016	to May 31, 2017	%
June 1, 2017	to May 31, 2018	%
June 1, 2018	to May 31, 2019	%
June 1, 2019	to May 31, 2020	%

June 1, 2020	to May 31, 2021	%
June 1, 2021	to May 31, 2022	%
June 1, 2022	to May 31, 2023	%
June 1, 2023	to May 31, 2024	%
June 1, 2024	to May 31, 2025	%
June 1, 2025	to May 31, 2026	%
June 1, 2026	to May 31, 2027	%
June 1, 2027	to May 31, 2028	%
June 1, 2028	to May 31, 2029	%
June 1, 2029	to May 31, 2030	%
June 1, 2030	to May 31, 2031	%
June 1, 2031	to May 31, 2032	%
June 1, 2032	to May 31, 2033	%
June 1, 2033	to May 31, 2034	%
June 1, 2034	to May 31, 2035	%
June 1, 2035	to May 31, 2036	%
June 1, 2036	to May 31, 2037	%
June 1, 2037	to May 31, 2038	%
June 1, 2038	to May 31, 2039	%

13.4 Exhibit D: Financial Offer

This information will be taken from the Supplier's Proposal to the Buyer's competitive solicitation process. All information submitted in the Proposal is binding at the date of Proposal's Financial Offer submission.

[To be attached after offer selection and contract execution]

13.5 Exhibit E Code of Conduct

Information Disclosure and Communication Protocols

1. The Buyer in this Agreement, and specifically any Parties representing the Buyer, will be obliged to sign a MDPSC Confidentiality/Non-Disclosure Agreement (Appendix 11 of the Request for Proposals For Generation Capacity Resources Under Long-term Contract) before receiving this Agreement, which will grant this Agreement the status of "Protected Materials."
2. The Confidentiality/Non-Disclosure Agreement shall be based on a Protective Order which will be approved by the MDPSC before the distribution company receives this Agreement.
3. As per the Confidentiality/Non-Disclosure Agreement, the electric company will put in place appropriate "Firewalls" (i.e. information barriers that prevent conflicts of interest regarding the sharing of information for gain or for achieving competitive advantage) to safeguard commercially sensitive information to which the companies will have access to once they become counterparties to this Agreement.
4. The electric distribution company will treat as confidential the Protect Materials it receives as an administrator of and counterparty to this Agreement. Protected Materials will not be used except as necessary for the administration of this Agreement, nor shall they be disclosed in any manner to any person except an official

"Reviewing Representative." A Reviewing Representative is a person who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out his or her responsibilities in this proceeding.

13.7 Exhibit F

Pricing Mechanism for Fixed/Indexed Price Contract for Differences

The mechanism for pricing of a Contract for Differences covering Capacity, and Associated Energy is defined below. The mechanism is based on a Fixed/Indexed pricing approach, subject to Supplier guarantees of capacity and heat rate.

Contract Quantities: *These quantities will be established at the time the contract is executed. The quantity may need to be modified if acceptance testing prior to Commercial Operation shows that the quantity has changed.*

CCQ = Confirmed Contract Quantity, MW

This is the quantity of unforced capacity (UCAP) that Supplier has offered to supply into the BRA and that Parties will settle against, as confirmed at the Facility's Commercial Operation Date.

CUFIC = Contract Unit Fuel Input Curve, as a function of unit output, operating mode (*e.g.*, inlet air chillers on/off, inlet air heaters on/off, duct firing, etc.), and cumulative degradation

CUSP = Contract Unit Start Fuel, MMBtu per unit start cycle

CO2ER = CO2 Emission Rate, lb/MMBtu

SO2ER = SO2 Emission Rate, lb/MMBtu

The carbon dioxide and sulfur dioxide emission rates are based on fuel composition.

FNOxER = Full Load NO Emission Rate, lb/MMBtu

The full load NO_x emission rate is based on plant design rate operating at full load.

SNOxER = Startup NO Emission Rate, lb/unit start cycle

The start-up NO_x emission rate is based on plant design or permit rate, whichever is more restrictive.

Contract Price Provisions:

CCP = Contract Capacity Price, $/MWucAp -day

For Generation Capacity Resources proposed on a Fixed / Indexed pricing basis, the CCP will be based on the proposed capacity pricing components.

CCP = (CPFirm + CPIndex * EscFactor)

CPFirm = Firm capacity price component, $/MWucAp -day

CPIndex = Indexed capacity price component, $/MWucAp -day (as proposed)

EscFactor = Escalation Factor

= Current year index value / Base index value for proposed index

VOMe = Variable Non-Fuel O&M Rate, $ / MWh

= CPVEFirm + CPVEIndex * EscFactor

VOMs = Variable Non-Fuel O&M Rate, $ / unit start

= CPVSIndex * EscFactor

CPVEFirm= Firm component of energy price, S / MWh (as proposed)

CPVEindex= Indexed non-fuel component of energy price base, $/MWh (as proposed)

CPVSIndex= Indexed start price base, $ / unit start (as proposed)

CFPA= Fuel Price Adder for delivery and balancing, $/MMBtu (as proposed)

CFPM= Fuel Price Multiplier for transportation losses (as proposed) HVCF= Heating Value Conversion Factor (Index units / MMBtu)

Monthly Costs and Quantities: *Calculated for each generating unit:*

UMEQ = Unit Monthly Energy Quantity, MWh

= UHEQi,c over all hours i in month and all operating modes c at or above the applicable Low Operating Limit

UHEQi,c = Hourly Energy Quantity in hour i, MWh for portion of hour in which unit operates in mode c at or above the applicable Low Operating Limit

OFi,c = Operating Factor, hour i in mode c

= fraction of hour i in which the unit operates in mode c at or above the applicable Low Operating Limit

Calculated as aggregate for all units:

MEQ= Monthly Energy Quantity, MWh = UMEQ for all units

MStrt = Monthly unit starts

The measures above are based on actual dispatch levels.

MACO2RQ = Monthly Actual CO2 Allowance Retirement Quantity, tons = MACO2Q x Applicable multiplier for multiple retirements

MASO2RQ = Monthly Actual SO2 Allowance Retirement Quantity, tons = MASO2Q x Applicable multiplier for multiple retirements

MANOxRQ = Monthly Actual NOx Allowance Retirement Quantity, tons = MANOxQ x Applicable multiplier for multiple retirements

If no multiple retirement requirement is in effect for a particular emission, the "applicable multiplier" is 1.00.

MACO2E = Monthly Actual CO2 Emission Allowance Expense, $ MASO2E = Monthly Actual SO2 Emission Allowance Expense, $ MANOxE = Monthly Actual NOx Emission Allowance Expense, $

MAEAE = Monthly Actual Emission Allowance Expense, $ = MACO2E + MASO2E + MANOxE

The actual emission allowance costs for CO2, SO2, and NO are calculated in accordance with generally accepted accounting principles for inventory valuation and recognition of allowance grants and deferred allowance purchases. Deferred purchases are to be accrued based on a published index, with an annual true up charge or credit to account for actual allowance purchase cost. The expense figures do NOT include any penalties that might be imposed for violation of air permit limits.

MCO2P = Monthly CO2 Allowance Price, $/ ton of retired allowances = MACO2E / MACO2RQ

MSO2P = Monthly SO2 Allowance Price, $/ton of retired allowances = MASO2E / MASO2RQ

MNOxP = Monthly NO Allowance Price, $/ton of retired allowances = MANOxE / MANOxRQ

Reference Quantities and Expenses: *Reference quantities and expenses are calculated as a function of actual output and contractual performance parameters to provide a basis for comparison of actual performance to contractual obligations. Fuel and allowance costs are reimbursed at actual prices applied to reference quantities for Generation Capacity Resources proposed on a Fixed/Indexed Pricing basis.*

For each unit:

UMRFC = Unit Monthly Reference Fuel Consumption, MMBtu

= Σ Σ (HRFCi,c) over all hours of the month and all modes c

HRFCi,c = Hourly Reference Liquid Fuel Consumption, MMBtu, for hour i and operating mode c

UMRFE = Unit Monthly Reference Fuel Expense, $

= Σ Σ (HRFCi,c) * DFPi over all hours of the month and all modes c

DFPi = Daily Fuel Price ($/MMBtu) applicable in hour i = FPId * CFPM * HVCF + CFPA

FPId = Value of Fuel Price Index on day d (which includes hour i)

For all units in aggregate:

MRFC = Monthly Reference Fuel Consumption, MMBtu = Σ (MStrt * CUSF + UMRFC) for all units

MRFE = Monthly Reference Fuel Expense, $

= Σ {(MStrt * CUSF + UMRFC) / UMRFC * UMRFE} for all units

MRCO2E = Monthly Reference CO2 Emission Allowance Expense, $

= MRFC * CO2ER / 2000 * Applicable multiplier for multiple retirements * MCO2P

MRSO2E = Monthly Reference SO2 Emission Allowance Expense, $

= MRFC * SO2ER / 2000 * Applicable multiplier for multiple retirements * MSO2P

MRNOxE = Monthly Reference NOx Emission Allowance Expense, $ = [MRFC * FNOxER + MStrt * SNOxER / 2000

* Applicable multiplier for multiple retirements * MNOxP

MREAE = Monthly Reference Emission Allowance Expense, $ = MRCO2E + MRNOxE + MRSO2E

Monthly Reference Variable Cost:

MRVC = Monthly Reference Variable Cost, $

= MEQ * VOMe + MStrt * VOMs + MRFE + MREAE

Fuel expenses and allowance expenses are compensated based on market or actual prices, but reference quantities using contract heat input curves reflecting output level, operating mode, and cumulative degradation.

Monthly PJM Market Revenues:

MER = Monthly Energy Revenue, $

= Σ (LMPi * [Offer and cleared net energy amount in DAM or RTM for hour i) over all hours of the month

MRR = Monthly RPM Revenue, $ = CCQ * RPMP * (days in month)

RPMP = RPM Market Price, $/MWucap -day

Monthly RPM Payment Amount:

MRPA= Monthly RPM Payment Amount, $ = (CCP - RPMP) * CCQ * (days in month) Monthly Energy Payment Amount:

MEPA = Monthly Energy Payment Amount, $ = MRVC MER

Monthly Payments:

MPA = Monthly Payment Amount, $ = MRPA + MEPA

MPA is paid by Buyer to Supplier if positive, by Supplier to Buyer if negative. If MPA is zero, then neither Party pays the other. The Supplier takes the quantity/availability, risk, while Buyer takes market price risk.

ATTACHMENT 9

CONFIDENTIALITY/NON-DISCLOSURE AGREEMENT

[Name and Address of the Respondent]

[Date]

Ladies and Gentlemen,

This letter is a Confidentiality Agreement between Electric_____Distribution Company ("EDC") and_____("Respondent") in connection with the Company's intent to participate in the Request for Proposals ("RFP") to Generation Capacity Resources. This Confidentiality/Non-disclosure Agreement also pertains to the rights and obligations of ("EDC") and the Respondent in the event that the Respondent's RFP offer is ultimately selected. The EDC and the Respondent hereby agree to accept and to be bound by the terms of this agreement.

DEFINITIONS:

(a) The following terms have the following meanings:

1. "Agreement" is this Confidentiality/Non-disclosure Agreement.
2. "Confidential Information" has the meaning set forth in Section (4.)
3. "Party" means either the Respondent or the EDC.
4. "Parties" means collectively both the Respondent and the EDC.
5. "Representatives" mean a party's employees, consultants, contractors, agents, auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees.
6. "Third Parties" means a party other than Supplier (Respondent), Buyer (EDC), or their respective representatives.
7. "Commission" means the Maryland Public Service Commission.

(b) Other capitalized terms used in this agreement have the meaning set forth in this agreement and/or the Request for Proposals dated

TERMS:

1. *Condition Precedent*. The EDC and the Respondent shall execute this Agreement as a condition precedent to EDC furnishing to the Respondent or the Respondent furnishing to the EDC a copy of any Confidential Information.

2. *Purpose.* The purpose of this agreement is to protect the confidentiality of the Confidential Information and to restrict the use and disclosure of that information in the manner set forth below.

3. *Limitations on Use and Disclosure.*

   (a) A party shall use the other party's Confidential Information only for the purpose of evaluating, responding to, negotiating and consummating the RFP and/or the response to the RFP, and/or performing under any resulting contract to provide Generation Capacity Resources and associated products, and not for any other purpose. Neither party shall disclose to Third Parties any information about the EDC's or Respondent's participation in the RFP or any resulting contract., or the terms or conditions or any other facts relating thereto, including the fact that discussions are taking place with respect thereto, the status of those discussions, or the fact that Confidential Information has been made available by or to either Party or their Representatives.

   (b) Notwithstanding the foregoing or any other provisions of the Agreement, the EDC may share any Confidential Information with the Maryland Public Service Commission ("Commission") or its Consultant working for the Commission. Any such information shared will be designated as Confidential Information, and the EDC will ask the Commission to hold and use it on a confidential basis.

(c) Notwithstanding any other provisions of this Agreement, a Party may disclose to its employees, representatives, and agents and to the Commission all documents and information furnished by the other Party in connection with this Agreement.

(d) Notwithstanding any other provisions of this Agreement, confidentiality status of information does not preclude it from being disclosed to either Party's Affiliates, and to either Party's auditors, attorneys, advisors, lenders, investors, potential acquirers, directors or trustees (collectively, "Representatives") who were not entering into or performing under this Agreement; provided, however, that any Representatives to whom either Party discloses the information shall be required to observe the terms of this Agreement.

(e) Any independent auditor performing an audit on behalf of a party shall be required to execute a confidentiality agreement with the Party being audited. Such audit information shall be treated as Confidential Information pursuant to this Agreement.

4. *Definition of Confidential Information.*

(a) Confidential Information shall consist of oral, electronic, or written information that is confidential, proprietary, or generally not available to the public. Whenever possible, such Confidential Information shall be marked prior to or at the time of disclosure as being "Confidential Information"

(b) The contents of this Agreement and all other documents relating to this Agreement and any information made available by a Party ("Disclosing Party") to the other Party ("Non-Disclosing Party") with respect to this Agreement are presumed to be public, unless the MDPSC has granted a request for confidential treatment.

(c) To obtain confidential treatment, the requesting Parties should notify the other parties that they seek confidential treatment under this agreement for specific data or information that they deem to be proprietary and confidential. In the case where the parties may not agree on the need for confidential treatment under the terms of this agreement, the requesting party may file a motion under seal with the commission to treat the information as confidential. The information frled under seal should clearly be marked "confidential" on the top of each page. The motion should indicate the basis in federal or state law for keeping the information confidential.

(d) Parties requesting confidential treatment from the MDPSC must clearly identify the information for they are requesting confidential treatment, for how long such confidential treatment shall last, and whether or not the information will be provided on a continuing basis or on a single occasion. Once the Commission has ruled that such information is confidential, the ruling will be valid for the duration of the

Term of this Agreement, unless such information has become non-confidential.

5. *Non-Confidential Information.* Not withstanding the provisions of Section 4, information shall not be deemed confidential that (i) becomes generally available to the public; (ii) is already known to the receiving Party a the time of receipt of the receiving Party; or (iii) is acquired after such receipt from a Third Party not known to the receiving Party to be prohibited from making disclosures. In addition, notwithstanding any other provision of this Agreement, the Respondent may always make public, at its sole discretion, the fact that it has made an offer in response to the RFP, whether the Respondents has been awarded a contract to provide a Generation Capacity Resource, the amount of the Capacity Resource and associated products awarded, and/or the price to be paid for those Products. The receiving Party shall give prompt notice to the other Party in the event it believes that any of the other Party's information in its possession is not Confidential Information as a result of the provisions of this Section 5.

6. *Property of the EDC or the Respondent.* Confidential Information belonging to the EDC shall consist of Confidential Information supplied by the EDC to the Respondent and shall also include the portion of Confidential Information furnished by the Respondent to the EDC that incorporates Confidential Information furnished to the Respondent by the EDC. Confidential Information belonging to the Respondent consists of all other Confidential Information supplied by the Respondent to the

EDC. EDC and Respondent acknowledge that each Party's Confidential Information is and at all times remains the sole and exclusive property of that Party, who, it is agreed, has the exclusive right, title, and interest to its Confidential Information. Neither Party grants any right or license, by implication or otherwise, as a result of the provision of Confidential Information to the receiving Party.

7. *Disclosure Prohibited Except Where Explicitly Permitted.* Neither Party shall disclose or use the other Party's Confidential Information without the other Party's prior written consent except as explicitly stated in Sections 3, 8, and 9 of this Agreement. The Parties will put in place appropriate information barriers that prevent conflicts of interest regarding the sharing of information for gain or for achieving competitive advantage to safeguard commercially sensitive information to which the companies will have access to once they become counterparties to this Agreement.

8. *Disclosure for Bid Evaluation Purposes.* A Party may disclose the other Party's Confidential Information to its Representatives for the purposes set forth in Section 3. The obligations and restrictions under this Agreement that apply to a Party also apply top a Party's Representative(s).

9. *Disclosure to Governmental Authorities.*

   (a) Notwithstanding any other provisions of this Agreement, Confidential Information may be disclosed to a third party as may be required in response to any summons or

subpoena from a regulatory body, or otherwise required in connection with any litigation or to comply with any applicable Law, order, regulation, ruling, regulatory request, accounting disclosure rule or standard or any exchange, control area or independent system operator rule (provided that the Non-Disclosing Party shall promptly notify the Disclosing Party, if possible prior to disclosure, so that Disclosing Party may seek a protective order or other appropriate remedy, or, in its sole discretion, waive compliance with the terms of this Agreement.

(b) A Party (the "disclosing Party") may also disclose the other Party's Confidential Information to any governmental, judicial, or regulatory authority ("Authority") requiring such Confidential Information; provided that, the disclosing Party (i) promptly informs, before disclosure if possible, the other Party of the substance of any inquiries, requests or requirements in order to afford the other Party an opportunity to attempt to prevent or limit the disclosure of the Confidential Information; (ii) makes a good faith effort to persuade the Authority that submission of the Confidential Information should not be required, or, if that effort fails, that submission of the Confidential Information on a non-public basis should be permitted; and (iii) endeavors in good faith to protect the Confidential Information provided to an Authority from disclosure to Third Parties.

(c) If an Authority orders the disclosing Party to disclose any documents containing the other Party's Confidential Information, the disclosing party shall a) attempt to obtain from the other Party, if the Authority allows the time, a "Public Disclosure Copy", or b) if the Authority does not allow such time, shall prepare itself a "Public Disclosure Copy" in which the Confidential Information has been redacted to the extent that such redaction is permitted by the Authority requiring disclosure. Confidential Information disclosed pursuant to this Section 9 on a non-public basis shall not lose its status as Confidential Information by virtue of such non-public disclosure.

10. *Termination of RFP Participation.* If the Respondent determines that it does not want to proceed with the RFP offer, or if the EDC excludes the Respondent from the RFP for any of the reasons set forth in the RFP, it will immediately notify the other Party of that decision. In such case, or if the RFP is not consummated, upon the written request of the Party ("requesting Party"), the other Party (the "receiving Party") shall not retain and shall promptly return to the requesting Party all of the requesting Party's written Confidential Information in the possession of the receiving Party or its Representatives, except for the portion ("said portion") of the requesting Party's Confidential Information that may be found analysis, compilations, or other documents prepared by, or for, the receiving Party and its Representatives. The said portion and any oral Confidential

Information furnished by the requesting Party and not so requested or returned will be held by the receiving Party sand kept subject to the terms of this Agreement, or destroyed.

11. *Liability and Relief.* A Party or any of its Representatives shall be liable for any breach of this Agreement. In the event a non-breaching Party or its Representatives shall have knowledge of any breach of the confidentiality of, or the misappropriation of, any of the Confidential Information, the non-breaching Party shall promptly give notice thereof to the breaching Party. The non-breaching Party shall be entitled to specific performance or other equitable relief by way of injunction or otherwise, if the other Party or any of its Representatives breach or threaten to breach any of the provisions of this Agreement. Such remedy shall not be deemed to be the exclusive remedy available to the non-breaching Party, but shall be in addition to all other available remedies. Neither failure nor delay by the non-breaching Party, in exercising any of its rights or privileges herein, shall operate as a waiver nor shall any single or partial exercise preclude any other or further exercise of any right, power, or privilege.

12. *Representatives, Successors, and Assigns.* This Agreement shall be binding upon and for the benefit of the Parties, and their respective Representatives, successors, and permitted assigns. Neither Party may assign its rights or obligations hereunder without prior written consent of the other Party.

13. *Controlling Law*. This Agreement shall be governed by and construed in accordance with the laws of the state of Maryland without regard to conflicts of laws, rules, or principles.

14. *Full Compliance Required*. The failure in any instance to insist on full compliance with the terms of this Agreement shall not be deemed to be a waiver of the right to insist upon full compliance with these terms thereafter.

15. *Signatures*. The signatures below establish each Party's agreement to the terms hereof.

16. *Termination* This Agreement shall terminate three years from the date hereof.

RespondentEDC

By_____ By_____

Title_____ By_____

PLAINTIFF EXH. NO. P143

CASE NO: 1:12-cv-01286

OUTLOOK E-MAIL

From: Craig Roach

Sent: 1/28/2011 12:53:57 PM

To: kgottshall@bostonpacific.com;
agisselquist@bostonpacific.com;
fmossburg@bostonpacific.com;
pwallach@bostonpacific.com;
Calvin Timmerman;
gcarmean@psc.state.md.us

Subject: RE: BPC Comments on the proposed MD RFP

Great. Thanks.

(Here in the deep south, we don't drive very well in the snow so we cause ourselves a lot of problems. All is well now. Hoped you fared well.)

Craig R. Roach, Ph.D
Boston Pacific Company, Inc.
1100 New York Avenue, NW
Suite 490 East
Washington, DC 20005
(202) 296-5520
croach@bostonpacific.com

From: Calvin Timmerman [mailto:CTimmerman@psc.state.md.us]

Sent: Friday, January 28, 2011 11:47 AM

To: Craig Roach; Gregory V Carmean

Cc: Katherine Gottshall; Andrew Gisselquist; Frank Mossburg; Peter Wallach

Subject: RE: BPC Comments on the proposed MD RFP

This looks good. Thank you. I'm going to put it a bit more in the context of a "Least Cost Plan" rather than traditional IRP. In our environment, the default cost comparison is really the estimated cost for "market resources" procured under shorter term contracts (like our SOS process). To buy any resource that exceeds that estimated cost you need to have some specific reason such as concern that the RTO reliability process will fail to provide adequate resources or you some other policy objective like GHG reductions. Reliability concerns lead to our Gap RFP for DR resources. In this case the Commission expresses concerns that RPM isn't producing adequate new capacity, but unlike the Gap RFP, PJM's numbers don't suggest any capacity crisis. It really seems to be the hope that this RFP will produce cheaper capacity and energy than you get from the market. I know this was some of what you wanted to say originally, and I'm coming around to adding that.

I think your work is done for now, unless there is some hint that there will be reply comments.

Hope you managed OK in the snow.

Calvin

From: Craig Roach [mailto:CRoach@bostonpacific.com]

Sent: Friday, January 28, 2011 11:04 AM

To: Calvin Timmerman; Gregory V. Carmean

Cc: Katherine Gottshall; Andrew Gisselquist; Frank Mossburg; Peter Wallach

Subject: FW: BPC Comments on the proposed MD RFP

Calvin, Greg:

Attached are two versions of our suggested comments. The first is a clean copy. The second is a red line showing what changed since the last version you reviewed.

Again, we (and you) could add a lot more to this, but I think plenty is being said and the most important threshold changes are included. Please let us know if you need anything more. We very much appreciate the opportunity to work on this with you. Thanks.

Craig R. Roach, Ph.D.
Boston Pacific Company, Inc.
1100 New York Avenue, NW

Exhibit PX 51
Wit: /s/ Nazarian
Date: 1/11/13
Reporter: J. Harmonison

PLAINTIFF'S EXH. NO. P203

CASE NO.: 1:12-cv-01286

Outlook E-mail

From: Frank Mossburg
Sent: 7/28/2011 9:54:39 AM
To: 'E. Frank Bender'
Cc: Peter Wallach; Katherine Smith
Subject: RE: Key Points Outline
Attachments OUTLINE FOR MD RFP (July 28).doc

Frank,

Attached please find the promised key points outline. This is essentially an outline of the testimony that we use to guide our thinking and conclusions that we've supplemented with data from our research. As we go forward we'll deepen and refine each point. I'd also caution that the document has not been data checked at this point, so please use caution when reviewing the data.

Since there's a lot here I'd recommend that you only spend a short time reviewing it and allow me to walk you through it in a phone call. Please let me know when a good time would be to talk. I'm particularly interested in your thoughts on our current recommendation regarding a planning process (see page 6-7). Is it something that you think would be valuable? Would the Commission be up for something like that or are they tired of studies/conferences/etc? Would it be duplicative of other efforts or mirror something that has been tried and failed?

Thanks,
Frank M

From: E. Frank Bender
[mailto:fbender@psc.state.md.us]
Sent: Tuesday, July 26, 2011 3:51 PM
To: Frank Mossburg
Subject: RE: Key Points Outline

Thanks. I await your outline.

I was wondering how the events of last week's heat wave, the resulting Demand Response complaints in Maryland and the rolling blackouts in New Jersey, might factor into any process that you recommend the Commission use to verify the need for additional generation capacity. Do you have any thoughts about it?

E. Frank Bender
Senior Commission Advisor
Maryland Public Service Commission
William Donald Schaefer Tower 6 St. Paul Street
Baltimore, Maryland 21202-6806
(410) 767-8132

From: Frank Mossburg
[mailto:fmossburg@bostonpacific.com]
Sent: Tuesday, July 26, 2011 3:25 PM
To: E. Frank Bender
Cc: Peter Wallach; Katherine Smith
Subject: Key Points Outline

Frank,

Just to keep you up to date. We have reviewed the comments, RFP and many other data sources and are

currently constructing a short "Key Points" outline which we will use to create the final report, I'm shooting to send it to you on Thursday at which point I'd be happy to walk you through it and get your thoughts on the outline, our current conclusions, and hear any questions you may have.

Let me know if you have any issues or concerns.

Thanks,
Frank M
Frank Mossburg
Managing Director
Boston Pacific Company, Inc.
1100 New York Ave, Suite 490 East
Washington, DC 20005 Phone: (202) 296-5520

This email has been scanned by the MessageLabs Email Security System. For more information please visit http://www.messagelabs.comlemail

Exhibit BP 8
Wit:
Date: 1/29/13
Reporter: J. Harmonison

DRAFT-JULY 28 - CONFIDENTIAL

KEY POINTS OUTLINE FOR MARYLAND REPORT

I. Introduction and Summary

II. The Impetus for the Draft RFP stemmed from reliability concerns raised several years ago and the failure of RPM to incent new in-State generation to deal with those concerns

a. On Dec 29, 2010, the Commission issued for comment a draft RFP for new generating resources located in and around Maryland. The draft RFP was issued due to concerns over reliability and the fact that RPM has failed to attract new generation in the State.

i. The Draft RFP asks for 1800 MW of Capacity, Energy Ancillary Services and Tier 1 Renewable Energy Credits (if applicable).

ii. The impetus for this REP stemmed first from PJM's 2007 Electric Planning Conference, in which PJM said Maryland would begin to experience shortages starting in 2011.

iii. A 2008 analysis produced by PJM also showed capacity shortfalls if various transmission lines (most notably the TRAIL line) were not in service as scheduled.

iv. Since that time PJM has also raised concerns regarding limits on the Capacity Emergency Transfer Limit (CETL) into MAAC from the Pleasant View 500/230 kW transformer.

v. RPM has failed to attract new generation in the State to combat these threats. Since 2006 a total of 202 MW of new generation has come on-line in the State.

1. The Southwest MAAC (SWMAAC) zonal capacity price in each RPM Auction has constantly been the same or higher than the RTO-wide price. The average price for SWMACC capacity has been $177.04/MW-day. For the non-constrained portions of PJM the average price has been about half of that, $88.65/MW-day.

2. Moreover, in five Base Residual Auctions the SWMAAC has the clearing price been at or above Net CONE (the theoretical price needed to attract new entry).

3. Despite this price premium, little new generation has appeared. Between the 2008-09 and 2013-14 RPM Auctions, only 242 MW of new capacity cleared in the SWMACC zone.

a. Most of RPM's draw has been demand-response resources. From the 2008-09 through the 2013-14 Auctions RPM 1,811 MW of net demand-response resources were bid into and cleared in the SWMACC Zone.

4. Looking at generation actually constructed reveals a similar picture. According to the PJM interconnection queue, there has only been 202.2 MW of new generation put on-line in Maryland since 2006, about half of that is due the repowering of an existing unit.

III. The Commission's Draft RFP attracted comment from a wide array of parties, some supporting issuance and some not. Nearly all parties requested clarifications or modifications

a. On January 28, 2011 a total of 27 parties filed comments. The comments covered a wide variety of subjects.

i. Many comments were related to the need for an RFP in the first place.

1. Multiple parties pointed to the necessity of a hearing to determine the reliability need for new generation, something contemplated in the Draft RFP

2. Several parties spoke out against the RFP because of potential chilling effects on merchant generation and capital investment. The general point being that, should the RFP happen, future developers would simply wait for subsidization from ratepayers rather than make their own estimates of market returns.

3. Others supported the RFP due to the above-mentioned failures of RPM to attract in-State generation.

4. Parties were also concerned about the time frame for the RFP, some wanted to push back the dates while others, particularly renewable developers who depend on time-sensitive tax credits, wanted the dates pushed forward.

ii. Almost all interveners requested changes or clarifications in the RFP itself

1. Many interveners identified the need to specify the type of supply that the Commission is interested in.

2. Another common thread was confusion over the role that the utilities would play in the bidding and bid evaluation. Specifically, would they be allowed or even required to submit bids.

3. Several parties also requested more detail as to how bids were to be evaluated, including what risks the bidder would have to accept.

4. Many parties requested clarification or made suggestions as to how the utilities would recover costs from these contracts, with different opinions as to whether the charges should be bypassable.

5. Several parties requested changes in the credit provisions, particularly the provision that required bidders or their guarantors to be investment-grade entities

IV. While there appears to be no immediate reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks and possibly bring economic benefits

a. An assessment of the current reliability situation finds that conditions have improved since 2007.

i. PJM's latest RTEP Report shows that risks to Maryland have been reduced somewhat due to a combination of lower than expected

load growth, increased demand response, and new transmission.

1. In its December 2008 report to the Maryland legislature, the Commission noted several scenarios in which there could be a generation shortfall, many of these had to do with the failure to construct the TrAIL line.

2. A review of the latest RTEP Report from PJM shows that several factors have combined to somewhat mitigate the previous reliability concerns.

a. The TrAIL line went into service in May of this year.

b. While the RTEP program originally identified the need for the PATH line in 2015, recent declining load projections have caused PJM to put a hold on the project.

c. Between the 2008-09 and 2013-12 RPM Auctions, 1,811 MW of net new demand-response supply bid into and cleared in the SWMAAC area

3. Despite this, RTEP still identities several projects that will require attention.

a. MAPP line required by 2015 to alleviate multiple issues

b. Mt. Storm-Doubs rebuild required as the "tower structures, foundations and conductors hard-ware have deteriorated to the point where the line is a approaching its end-of-life and is at risk of major failure"

c. Retirements of units at Benning road and Buzzard Point, totaling 788 MW of capacity, are expected to cause reliability issues that are being addressed_

d. Many smaller local projects are also identified, including a new substation to address the Pleasant view transform r contingency.

ii. Other indicators point to an improved reliability picture

a. RPM prices in SWMAAC have declined. The most recent RPM clearing price in SWMAAC is down from $226.15.MW-day to $ 136.50/MW-day.

i. Since the December 2008 report, the SWMAAC clearing price has averaged $165.34/MW-day compared to $184.05/MW-day in prior Auctions.

b. CETL/CETO ratios have improved.

i. The CETL/CETO ratio compares amount of capacity an LDA can import versus the amount it must import to avoid a Loss-of-load event of once every 25 years. The lower the ratio, the "tighter" the supply line into the LDA. If the ratio is less than 1.15 the LDA must be modeled as a separate zone.

ii. Last year the ratio in SWMAAC was 1.17 in the 2012-13 auction is was 1.24. In the most recent Auction, due to lower load projections and transmission improvements it was 1.42. This factor was sited as one reason for the price decrease.

c. Announced retirements have been minimal. While the units at Benning Road and Buzzard

point are due to retire in May of 2012, no other in-state units have announced plans to retire.

d. New generation is still in the queue. There is about 4,100 MW of new in-state generation that is currently listed as Active in the PJM Queue. While the majority of this supply will likely not be constructed, the number shows that there are still those who are planning to build in Maryland.

b. Despite this improvement, there are still four key risk factors that could affect the State's need for new capacity

   i. One, load growth could be higher than expected.

      1. The most recent PJM load forecasts reflect a decrease from last year. For example, the forecasted BGE Summer Peak for the year 2012 dropped 4%, from 7,781 MW to 7,460 MW.

      2. While this is positive for reliability it is important to note is that load estimates can fluctuate a great deal from year to year

a. For example, if we look at PJM's estimates for BGE Summer peak load for the year 2016 for the past 5 years we see a range from 7,902 MW to 8,351 MW This is a swing of almost 450 MW.

b. The longer out we look the larger the swings. For the last five years PJM's Pepco Sumer Peak estimate for 2022 has swung from 7,771 MW to 8,642 MW a swing of 871 MW, larger than a single new combined-cycle facility.

c. Swings can be seen even within a year-to year change. For example, the forecast BGE summer peak for 2016 increased from 7,98l MW to 8,304 MW in just one year as the result of the estimated impact of the U.S. Military's Base Realignment and Closure Program.

3 Other sources tell a similar story. For example, in the Commission's most recent Ten-year Plan (issued in February of 2010) the Maryland utilities' Peak Demand forecasts (net of DSM programs) for the 2015-2022 period drop about 9%, or over 1,300 MW. Again, this is the size of two new combined cycle units.

ii. Two, retirements could be greater than predicted.

1. As noted above, there are currently 790 MW of scheduled retirements in Maryland.

2. Recent proposed EPA rulings could force more shutdowns a. The EPA has proposed four regulations covering: (a) Clean Water Act Section 316(4 Cooling Water Intake Structures. (b) Title 1 of the Clean Air Act ¬Maximum Achievable Control Technology (MACT), (c) the Clean Air Transport Rule, and (d) Coal Combustion Residuals Disposal Regulations

3. Estimates of the effect of these regulations vary, but many studies show them to be significant.

a. The Brattle Group estimates 8.3 GW of possible closures across all of PJM.

b. NERC estimates retirements in RFC of between 5.25 and 13.15 GW

c. CRA predicts that there could be up to 7.5 GW of coal retirements in the near future. They estimate that, should this happen, RIM's capacity surplus (i.e. capacity in excess of forecasted reliability requirements) will drop from 10,789 MW to 3,860 MW.

d. PJM cited the cost of retrofits to coal units as one reason that the RPM price for the RTO as a whole increased in the most recent Auction.

4. In the most recent RTEP report PJM conducted a sensitivity run in which coal-fired units more than 40 years old were replaced by renewables. This had the effect of moving the estimated year of future NERC thermal criteria violations up by as many as 4 years. For example, violations on the Jacks Mountain to Juniata 500 kV path move up from 2020 to 2016.

5. This sensitivity likely only considered about 3,400 MW (or about one-quarter of the State's capacity) to be at risk. If we look more broadly at Maryland's generating capacity we see that about two thirds is more than 30 years old, this includes all the nuclear capacity in the State. According to an EIA report, coal and nuclear generation made up almost 90% of all electricity produced in Maryland in 2007.

iii. Three, Transmission projects could fail to be completed as scheduled.

1. Transmission projects represent an important way for Maryland to satisfy its electricity needs. According to the Commission's most recent 10-year plan, Maryland imported 29% of its electricity in 2007. Delays in planned transmission projects create a real risk for the State.

2. MAPP could be delayed, the project has yet to receive ifs CPNC from the Commission and requires numerous other permits.

3 Other improvements could not occur as scheduled

iv. Four, increased penetration of renewables could put extra strain on the transmission system.

1. In the most recent RTEP report, NM estimated the impact of integrating enough wind resources to satisfy all state RPS requirements. The effect was to move up the occurrence of NERC thermal criteria violations by as many as 5 years. For example, the Keystone to Conemaugh 500 kV path sees thermal violations move from 2025 to 2020.

v. All of these risks could create a need for new generation. Because of this, they should be acknowledged and incorporated into any planning process.

c. The economic benefits of new generation are potentially great, but very uncertain

i. New generation in SWMAAC could serve to lower the RPM price, but PJM's recent

revision of its MOPR may prevent this benefit from occurring.

ii New, more efficient capacity could lower local LMPs However, since the majority of Maryland's residential supply is priced based off the forward market, these benefits will likely not immediately translate into lower prices.

d. The Commission should establish an IRP-style collaborative planning process to fully vet the extent of these risks and the economics of various solutions. If the Commission determines that these risks are significant, it should then proceed with an RFP that will mitigate these risks.

i. Because the immediate threat to reliability appears to have lessened, the Commission does not have to immediately issue an RFP

ii. However, since risk factors such as swings in load estimates, and retirements can be significant the Commission should establish a forum to assess these risks.

iii. A collaborative planning process could be an appropriate forum. The process should feature

1. Collaborative development of inputs (e.g. cost of new capacity, load and fuel forecasts)

2. Modeling to determine need for new supply and the most cost-effective form of supply (e.g. capacity, demand response, etc.). Specifically, Capacity Expansion Modeling should be employed to

determine the cheapest resources to satisfy state needs and the timing of those resources. This type of modeling looks at the future needs of an area, current available resources, and potential resources to fill any futures gaps in supply. The model then picks the optimal resources and timing to fill the need, creating a supply plan going forward.

3. Modeling should include scenario analyses of the effect of changes in load, fuel prices, and emission costs on the type and timing of new supply need.

iv. Once the process identifies a solution the Commission could then issue an RFP which will competitively solicit the necessary resource

V Should the Commission move forward with a procurement, the RFP should explicitly state what is requested and transparently describe the evaluation process.

a. Should the Commission wish to issue the RFP, a number of edits should be made to ensure that it gets the best result.

b. The RFP should specifically define the product it is looking for. This will make bid evaluation easier. The need and timing should link to the IRP process as described above.

i. We assume that the commission will look for new dispatchable capacity

c. Bid evaluation procedures, including non-price scoring criteria, should be clearly spelled out, with the goal being a "price mostly evaluation"

i. We suggest a two stage evaluation, first a shortlist which selects the cheapest bids based on a levelized NPV then a full production cost modeling of these top bids.

ii. Uncertainty must be allowed to play a role in bid evaluation. Portfolios should be tested against changes in CO2, load, and natural gas prices at a minimum.

iii. Higher scores must be given to bidders who manage risk.

iv. Non-price scoring criteria should be spelled out and should ideally act as a "tiebreaker"

v. Bidders should also provide changes to standard form contracts. While some deviations can be allowed, any offer which substantially redirects risk onto ratepayers should not be permitted.

d. No cost of service offers or pass-throughs should be allowed. Bidders could be allowed to submit their initial offer as "indicative" and then bidders on the final shortlist could submit final fixed offers.

e. The RFP and contracts must clarify the risk posed by PJM's Minimum Offer Price Rule

i. A key risk, as evidenced by the LCAPP process in New Jersey, is that a facility will not clear the RPM Auction and leave ratepayers paying twice for capacity The REP originally contemplated a bidder offering a zero-price bid to ensure clearance, but recent changes to PJM's MOPR have removed that possibility.

ii. There are a number of possible ways to deal with this risk.

1. The bidder could take the risk and not receive capacity payments if it does not clear RPM. This will protect ratepayers, but make the contract less enticing to bidders and harder to finance.

2. The ratepayers could take the risk and ensure that the facility will receive its capacity payment. This will ensure a financible contract, but leave the risk that ratepayers pay twice for capacity.

3. The State could attempt to utilize the Fixed Resource Requirement (ERR) under which it withdraws from RPM, but this would require a multi-year commitment, remove any benefit from participation in RPM and prove difficult to enact given the deregulated marketplace in Maryland.

iii. We would recommend that ratepayers never shoulder the risk of paying twice for capacity. The bidder should manage the risk. The State could aid in this effort by staying involved with PJM's effort to revise its new entry pricing adjustment (NEPA) and making sure that the NEPA is a realistic option that generators can use to avoid being mitigated under MOPR and supply capacity to ratepayers.

1 PJM has recently suggested that it will try and propose a NEPA that will feature a voluntary multi-year auction which will

match buyers and sellers of long —term (i.e. 5 to 9 year) capacity.

f. Other suggested edits

i. Remove investment grade requirement

ii. Accommodate longer construction times.

VI. Conclusions

a. Collaborative IRP Process

b. RFP targeted to resources identified under process.

PMJ—At a Glance

[PLAINTIFF'S EXH. NO. P516]

CASE NO.: 1:12-cv-01286

[GRAPHIC]

PML coordinates the movement of electricity in all or part of the 13 states and the District of Columbia. We work quietly behind the scenes. Our job is to ensure there is enough electricity for the 60 million people in our region.

Keeping the Lights On

We're sometimes called air traffic controllers of the power grid. PJM monitors and coordinates more than 1,365 electric generators, 59,750 miles of high-voltage transmission lines and 6,224 substations. Just like air traffic controllers, we don't own the equipment we direct. Others own the power lines and power plants.

Power generators, utilities and power marketers coordinate their operations through PJM. Doing so makes major electric outages less likely to occur and reduces power costs.

KEY STATISTICS	PJM TODAY
Millions of people served	60.1
Miles of transmission lines	59,750
Generation capacity in MW	185,600
Square miles of territory	214,000
Area Served	13 states + D.C.

High Technology

Our operations are based on skilled knowledge workers and banks of powerful computers. Expert staff constantly monitor the grid at PJM's high-tech data, communication and control centers. As usage of electricity shifts up and down throughout the day, PJM balances supply and demand by telling power producers how much energy to supply.

Our engineers and information technology experts study hundreds of "what if" scenarios. They prepare to deal with virtually any event—from extreme weather conditions, emergencies and equipment failures, to the more easily anticipated cycles of days, weeks and seasons.

Planning

PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets. PJM's RTEP process employs a 15-year planning horizon to better address major transmission investments and upgrades that will maintain grid reliability and improve economic efficiency.

Power Markets

PJM administers competitive wholesale markets for large blocks of electricity—similar to the way the stock market works. Our markets are Internet based. Utilities and other electricity suppliers use them to make short-term purchases of power for their customers. Our markets attract alternative power sources, such as wind, to the region.

We administer demand response programs that help keep electricity prices as low as possible. Demand response allows customers to be paid for reducing their electricity usage during periods of higher power prices.

A Long History

Founded in 1927, PJM Interconnection is an independent, federally regulated organization headquartered at Valley Forge, Pa.

PJM'S ROLE AS AN RTO

PJM Interconnection is a regional transmission organization (RTO), an entity authorized by the federal government to manage the reliability of the electric transmission system and the operation of the wholesale electricity market in a defined control area.

PJM received full RTO status from the Federal Energy Regulatory Commission (FERC) in December 2002.

PJM serves as the RTO for a 214,000-square-mile control area that covers all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, with a population of about 60 million.

As an RTO, PJM coordinates and directs the operation of the region's transmission grid, which includes 6,185 substations and 59,750 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

According to the FERC, RTOs are designed to "promote efficiency in wholesale electricity markets

and ensure that electricity consumers pay the lowest price possible for reliable service."

The FERC determined that PJM met the four required characteristics of an RTO and could perform the eight functions of an RTO.

The four required characteristics are:

- Independence—the RTO must be independent of any market participant.
- Scope and regional configuration—the RTO must serve an appropriate region.
- Operational authority—the RTO must have operational authority for all transmission under its control.
- Short-term reliability—the RTO must have exclusive authority for maintaining the short-term reliability of the grid it operates.

The eight functions of an RTO are:

- Tariff administration and design—the RTO must administer its own transmission tariff and employ transmission pricing that promotes efficient use and expansion of transmission and generation.
- Congestion management—the RTO must develop and operate market mechanisms to manage transmission congestion.
- Parallel path flow—the RTO must develop and implement procedures to address parallel path flows within its region and with other regions.
- Ancillary services—the RTO must serve as a provider of last resort of all ancillary services required by FERC Order 888 and subsequent orders.

- OASIS, Total Transmission Capability (TTC) and Available Transmission Capability (ATC)—the RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.
- Market monitoring—the RTO must provide objective monitoring of the markets it operates to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions.
- Planning and expansion—the RTO must be responsible for planning and directing needed transmission expansions, additions and upgrades that enable it to provide efficient, reliable and non-discriminatory transmission service, coordinating its planning with appropriate state agencies.
- Interregional coordination—the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

9/21/2012

PJM GOVERNING DOCUMENTS

PJM Interconnection's day-to-day operations and interactions with its members are outlined in a series of governing documents that establish and define the roles, responsibilities, authorities and obligations of PJM and its members. The three documents are the PJM Open Access Transmission Tariff, the Operating Agreement and the Reliability Assurance Agreement.

PJM's governing documents ensure the reliability of the electric power grid. The PJM manuals support

these agreements and contain the operating, planning, accounting and administrative procedures that PJM and its members follow to carry out its mission.

The *PJM Open Access Transmission Tariff* is the overall document that governs the operations of PJM. The tariff includes the provisions governing transmission service within the PJM region. The tariff and revisions to it and the other governing documents are subject to the approval of the Federal Energy Regulatory Commission (FERC), the agency that regulates PJM and the other regional grid organizations.

The *Operating Agreement* must be signed by organizations to become members of PJM. It contains provisions establishing how PJM operates as a regional transmission organization. It defines the roles and responsibilities of the PJM Board of Managers, the Members Committee and the Office of the Interconnection, which carries out the provisions of the governing documents in managing PJM's operations, planning and markets.

The *Reliability Assurance Agreement*, signed by all the load-serving entities in the PJM region, the organizations that sell electricity to end-use customers, establishes obligations and standards for maintaining the reliable operation of the electric grid in the PJM territory. It includes provisions related to ensuring adequate capacity resources, providing assistance during emergencies and planning for the future needs of the system.

Another document, the Transmission Owners Agreement, is signed by the transmission-owning members of PJM, those members that own transmission facilities or lease them with rights that are equivalent to ownership. The agreement provides for

the coordinated planning and operation of transmission assets in the PJM region, transfers some planning and operating responsibilities to PJM and establishes regional transmission service as provided for in the PJM tariff.

3/29/2012

FEDERAL POWER ACT
SECTIONS 205 and 206

PJM Interconnection's stakeholder process is designed to identify, review and make decisions about proposed revisions to PJM's governing documents, processes, market design and reliability operations. The review standards under Sections 205 and 206 of the Federal Power Act have a direct effect on how proposed revisions to PJM's governing documents are filed and reviewed by the Federal Energy Regulatory Commission.

Sections 205 and 206 of the act deal with the authority of the FERC over a public utility's rates, terms and conditions for transmitting or selling electric energy in interstate commerce. The rates, terms and conditions are required to be just and reasonable and not unduly discriminatory or preferential; otherwise, they are deemed unlawful. This is generally referred to as the "just and reasonable" standard.

Because PJM's governing documents relate to the transmission and sale of electricity in interstate commerce, changes to the governing documents—the Operating Agreement, the Open Access Transmission Tariff and the Reliability Assurance Agreement—must be accepted by the FERC.

Sections 205 and 206 establish the standards for demonstrating why a proposed revision to a governing document should be approved by the FERC.

Section 205 requires that the proposer of a revision demonstrate that the proposed rate, term or condition is just and reasonable. Section 206 requires that the proposer of a revision meet a higher burden of proof: it must demonstrate not only that the proposed change is just and reasonable, but also that the existing provisions are unjust and unreasonable.

In PJM's governance process, the Members Committee has Section 205 filing authority over the Operating Agreement, while the PJM Board has Section 205 filing authority over the Open Access Transmission Tariff (with the exception of certain provisions that are under the exclusive control of the PJM transmission owners) and the Reliability Assurance Agreement.

A party that doesn't have Section 205 authority over one of the governing documents may propose a revision to the document by making a Section 206 filing to the FERC, requiring that it meet the higher burden of proof.

For example, if the Members Committee votes against a proposed revision to the Operating Agreement, the PJM Board may decide that it is necessary to proceed and file the proposed revision at the FERC. If it does want to move forward at the FERC, PJM must file under Section 206 (instead of under Section 205) and prove that the existing Operating Agreement language at issue is unjust and unreasonable, and that the proposed language is just and reasonable.

2/15/2013

RELIABILITY

PJM Interconnection manages the electric grid to ensure the highest level of reliability. There are two significant aspects of reliability—adequacy and security.

In electric reliability terms, *adequacy* ensures that there are sufficient electric generating resources, including reserves or back-up electricity, to meet customer demand for energy during extreme conditions. Adequacy also ensures that the transmission system will be able to meet customer needs reliably in the future.

PJM's Reliability Assurance Agreement requires each load-serving entity—an organization that provides electricity to retail customers in the PJM area—to secure electric generating resources to cover the load it serves plus a reserve margin. These generating resources must be dedicated to PJM's operational control so that PJM can call on them if they are needed to meet the demands on the system.

The Reliability Pricing Model, the capacity-market approach that PJM implemented in 2007, is designed to ensure the future availability of the capacity resources, including demand response and energy-efficiency resources, that will be needed to keep the regional power grid operating reliably for consumers.

Through PJM's Regional Transmission Expansion Planning process, future adequacy requirements for new generation and transmission resources are identified using a 15-year planning horizon.

The second aspect of reliability, *security*, involves operating the electric power system in a way that anticipates the possibility of the failure of key

elements of the system, guards against a cascading failure of other elements and ultimately minimizes the loss of service to large groups of customers.

Security involves making operating adjustments so that the system is prepared for and protected in the event of a sudden, unexpected disturbance or failure. It also allows operators the flexibility to adjust to conditions in real time to protect the system.

2/11/2013

PJM'S MARKETS

PJM Interconnection operates the world's largest wholesale electricity market as the regional transmission organization for the area that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM's competitive wholesale electricity market began operating in 1997. Based on its success, PJM since then has led a dynamic process that has expanded the number and kinds of markets available to its more than 750 members.

PJM employs a collaborative process to establish systems and rules that ensure that its markets operate fairly and efficiently.

Using sophisticated information technology, PJM offers a variety of online resources and eTools to assist market participants in conducting business. The independent external market monitor evaluates PJM's operations and markets to detect design flaws in the operating rules, standards and practices or structural problems in the markets that may need to be addressed.

The following is a summary of the markets PJM operates:

Energy

PJM coordinates the continuous buying, selling and delivery of wholesale electricity through the Energy Market. In its role as market operator, PJM balances the needs of suppliers, wholesale customers and other market participants and monitors market activities to ensure open, fair and equitable access.

PJM's Energy Market operates much like a stock exchange, with market participants establishing a price for electricity by matching supply and demand. The market uses locational marginal pricing that reflects the value of the energy at the specific location and time it is delivered. If the lowest-priced electricity can reach all locations, prices are the same across the entire grid. When there is transmission congestion, energy cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal price (LMP) is higher in those locations.

The Energy Market consists of Day-Ahead and Real-Time markets. The Day-Ahead Market is a forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.

The Real-Time Market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions and are published on the PJM Web site. PJM settles transactions hourly and issues invoices to market participants weekly.

PJM also operates a Day-Ahead Scheduling Reserve Market. It obtains supplemental, 30-minutes reserves that may be needed to deal with unanticipated system conditions during the actual operating day.

Capacity

To ensure the future availability of the generating capacity and other resources that will be needed to keep the regional power grid operating reliably for consumers, PJM developed a new method of pricing capacity called the Reliability Pricing Model (RPM). It was implemented in 2007

Capacity represents the need to have adequate generating resources—"iron in the ground"—to ensure that the demand for electricity can be met at all times. In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract or with capacity obtained through PJM's capacity-market auctions.

The RPM system includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity — not just generating plants, but demand response and energy-efficiency programs as well. It works in conjunction with PJM's regional planning process to ensure the future reliability of the system.

The essential elements of the RPM capacity market are procurement of capacity three years before it is needed through a competitive auction; locational pricing for capacity that varies to reflect limitations on the transmission system's ability to deliver electricity

into an area and to account for the differing need for capacity in various areas of PJM; and a variable resource requirement to help set the price for capacity.

The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through bilateral contracts.

Financial Transmission Rights

PJM also operates a market for financial transmission rights (FTRs) to assist market participants in hedging price risk when delivering energy on the grid.

FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly energy-price differences across a transmission path in the Day-Ahead Market.

The FTRs provide a hedging mechanism that can be traded separately from transmission service. This gives all market participants the ability to gain price certainty when delivering energy across PJM.

Market participants can obtain FTRs in four ways:

- They can bid for them in PJM's long-term auction, in which FTRs are available for periods from one to three years.
- They can bid for them in PJM's annual auction, in which FTRs for the entire transmission capability of the system are available.
- They can bid for them in the monthly auctions at which leftover FTRs are sold.
- They can buy them in the secondary market in a transaction with another market participant.

Ancillary Services

Ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers.

PJM currently operates two markets for ancillary services—regulation and synchronized reserve.

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired frequency. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party or by buying it on the regulation market.

Synchronized reserve service supplies electricity if the grid has an unexpected need for more power on short notice. The power output of generating units supplying synchronized reserve can be increased quickly to supply the needed energy to balance supply and demand. LSEs can meet their obligation to provide synchronized reserve to the grid by using their own generation, by purchasing the required synchronized reserve under contract with another party or by buying it on the synchronized reserve market.

3/8/2012

RELIABILITY PRICING MODEL

To ensure the future availability of the generating capacity and other resources that will be needed to keep the regional power grid operating reliably for consumers, PJM developed a new method of pricing capacity called the Reliability Pricing Model (RPM).

The new capacity-market approach was implemented in 2007.

In order to maintain the reliability and stability of the electric transmission system, the organizations that manage the grid operate the system to keep power in balance—to match consumers' demand for electricity with the resources to meet that demand on an instantaneous basis.

Operating the electric grid involves balancing three elements—generation, transmission and demand for electricity. Because electricity is a speed-of-light product that cannot be stored, PJM must respond instantly to changes in demand and operating conditions across the grid in its territory. The PJM grid serves 60 million people in 13 states and the District of Columbia in the Mid-Atlantic, Midwest and South.

Capacity represents the need to have adequate generating resources—"iron in the ground"—to ensure that the demand for electricity can be met at all times. In PJM's case, that means that a utility or other electricity supplier is required to have the resources to meet its customers' demand plus a reserve. Suppliers can meet that requirement with generating capacity they own, with capacity purchased from others under contract or with capacity obtained through PJM's capacity-market auctions.

Generators (or other resources like demand response) must receive enough revenues to cover their costs, even if they operate infrequently. Payments for capacity provide a revenue stream to maintain and keep current resources operating and to develop new resources.

With its low capacity prices, the pre-2007 short-term capacity system was not producing sufficient new investment in the right locations to meet future needs. Although PJM as a whole had sufficient generating capacity, the pace of generation development had slowed because of the low capacity prices, while electricity demand was rising. In addition, the low prices had forced needed generation in certain areas to retire. But, because the units were needed for local reliability, PJM prevented them from retiring and paid them a premium to stay online.

Planned retirements of existing generating plants, cancellations of planned generating projects and projected load growth all represented a significant challenge to maintaining reliability in the future. Low capacity prices in the region meant that revenues weren't sufficient to cover the cost of investing in new generating plants.

The RPM system continues to follow a market approach to obtaining the capacity needed to ensure reliability, but includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity ¬resources that include not just generating plants, but demand response and energy-efficiency programs.

Investors need sufficient long-term price signals to encourage the maintenance and development of generation and other resources. The RPM plan, based on making capacity commitments three years ahead, creates long-term price signals to attract needed investments in reliability in the PJM region.

The essential elements of the RPM capacity market are:

- Procurement of capacity three years before it is needed through a competitive auction;
- Locational pricing for capacity that varies to reflect limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- A variable resource requirement to help set the price for capacity.

The RPM includes the continued use of self-supply and bilateral contracts to meet capacity obligations. The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through bilateral contracts.

The three-year forward auction allows for competition between new resources and existing resources.

Under the RPM, demand resources have real opportunities to compete with generation to provide resources needed to ensure reliability. Load-serving entities can supply their energy requirements through generation, demand response or energy-efficiency programs.

Demand resources can submit bids to reduce demand in the RPM capacity-market auctions, and those bids are eligible to set the market-clearing price for capacity. For the first time, energy-efficiency programs were able to participate in the 2009 auction.

Of the capacity that cleared in the May 2012 auction for the 2015/2016 delivery year, 14,833 megawatts (MW) were from demand resources, a five percent increase from the previous year's auction. At 923 MW cleared, energy-efficiency resources showed a 12 percent increase from the 2011 auction.

About 7,323 MW of new generating capacity were offered in the auction, including 6,844 MW of new generation resources and 479 MW of upgrades to existing generation.

Clearing in the auction were 4,899 MW of new generation resources, a record number for new generation resources cleared in a single RPM auction.

The RPM auctions that began in 2007 have provided a total of 52,181 MW of capacity resources that wouldn't have been available without the RPM.

The RPM capacity-pricing method is driven by the need to keep the grid operating in balance ¬satisfying the demand for electricity at every location in the region, now and in the future. By providing price signals to encourage capacity investment, the RPM helps ensure that the PJM region's consumers continue to receive reliable supplies of electricity at a reasonable cost.

5/21/2012

LOCATIONAL MARGINAL PRICING

PJM Interconnection uses a system called locational marginal pricing (LMP) to establish the price of energy purchases and sales in the PJM wholesale electricity market. LMP takes into account the effect of actual operating conditions on the transmission system in determining the price of electricity at different locations in the PJM territory.

Locational marginal pricing reflects the value of the energy at the specific location and time it is delivered.

- When the lowest-priced electricity can reach all locations, prices are the same across the entire PJM grid.
- When there is heavy use of the transmission system, the lowest-priced energy cannot flow freely to some locations. In that case, more-expensive electricity is ordered to meet that demand. As a result, the locational marginal prices are higher on the receiving end of the congestion and lower on the sending end.

Congestion—the heavy use of the transmission system in an area—generally raises the LMP in the receiving area of the congestion and lowers the LMP in the sending area. Operating conditions that limit the delivery capacity of specific transmission lines also can contribute to congestion and result in LMP changes.

LMPs are calculated by PJM's computer systems and posted on www.pjm.com every five minutes. This enables market participants to factor the information into their decision-making. (The current system demand, forecast demand and zonal LMPs are shown on the PJM home page; additional LMP information is available by choosing "Operational Data" or "eData Guest" from the PJM Data Shortcuts on the home page.)

The calculations used to determine LMPs take into account electricity demand, generation costs and the use of and limits on the transmission system. The LMP tells PJM market participants the cost to serve the next megawatt of load at a specific location. The calculations factor in all the available generating

sources to come up with the mix that creates the lowest production cost, while observing all limits on the transmission system.

The use of actual operating conditions and energy flows in determining LMPs encourages the efficient use of the electric grid and enhances reliability. LMPs give price signals that encourage new generation sources to locate in areas where they will receive higher prices. It signals large new users to locate where they can buy lower-cost power. It also encourages the construction of new transmission facilities in areas where congestion is common, in order to reduce the financial impact of congestion on electricity prices.

LMPs reinforce the reliability of the electric grid. They provide price signals that make market participants partners with PJM in maintaining reliability. With the information about grid conditions provided by LMPs, market participants can see when and where the system is stressed. Prices also tell market participants when congestion or supply shortages are taking place and allow them to react quickly to the situation.

3/26/2012

REGIONAL TRANSMISSION EXPANSION PLAN

Managing the future growth of the electric system is an integral part of PJM Interconnection's role as a regional transmission organization (RIO). PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid are needed to ensure reliability and the successful operation of the wholesale markets.

Using an open process, PJM plans for the growth of the electric grid in its region to ensure that future needs are met for both the reliability and the economic performance of the grid. PJM's RTEP process employs a 15-year planning horizon to better address major transmission investments and upgrades that will maintain grid reliability and improve economic efficiency.

The regional plan is the end result of a continuing, systematic process to make necessary transmission improvements. Transmission upgrades keep the system in compliance with reliability standards. These standards ensure that the system continues to deliver electricity throughout the region, which covers 13 states and the District of Columbia. The improvements also accommodate the interconnection of new generating projects.

The decision to build a new electric generating plant or a transmission line is significant, since these construction projects are costly, time-consuming and subject to numerous regulatory approvals. At the same time, decisions to add generation or transmission resources cannot be made in a vacuum because these projects affect the overall operation of the grid and its ability to deliver power to customers reliably.

The RTEP process systematically and objectively evaluates proposed transmission upgrades and generation interconnections to make sure that compliance with reliability criteria is maintained. The process also includes a mechanism to mandate necessary grid improvements. PJM's planning process began in 1997; its first regional plan was approved in August 2000.

The process accommodates not only expansion projects proposed by transmission owners, typically

electric utilities, but also merchant generation and transmission projects that are financed by private investors instead of utilities.

PJM's open and extensive review process ensures that all interested parties, including state regulatory agencies, have an active role in planning for future electricity supply and reliability needs. As part of the RTEP process, projects are reviewed by the PJM Board. Once a project is approved by the board, it is incorporated into the plan.

PJM also is expanding the analysis in its planning process beyond reliability and market-efficiency criteria to include state and federal public-policy requirements.

The RTEP process determines the need for and benefits of a transmission project; it does not review or approve a transmission line's siting. That is the responsibility of the affected states.

Under PJM agreements, transmission owners are obligated to build transmission projects that are needed to maintain reliability standards and that are approved by the board.

Since 2006, the board has authorized several backbone transmission projects that are included in the regional plan.

Two of those projects, both 500 kilovolts (kV), entered service in 2011. The 502 Junction to Loudoun line, also known as the Trans-Allegheny Interstate Line, runs from southwestern Pennsylvania to Loudoun, Virginia. The Carson-Suffolk line is located in southeastern Virginia.

Another authorized facility, currently in the permitting process, is the Susquehanna-Roseland

Project, a 500-kV line running from the Susquehanna Substation in Pennsylvania to the Roseland Substation in New Jersey.

Two other planned backbone projects were put in abeyance and removed from the RTEP by the PJM Board in 2011 because of uncertainties about when they would be needed in light of lower load forecasts.

- The Potomac-Appalachian Transmission Highline, a 765-kV line running from the Amos Substation in West Virginia to the Kemptown Substation in Maryland.
- The Mid-Atlantic Power Pathway, a 500-kV line running from the Possum Point Station in Virginia to the Indian River Substation on the Delmarva Peninsula.

To date, transmission investments authorized under PJM's RTEP since 2000 total about $23.4 billion, including upgrades to enable the interconnection of more than 44,000 megawatts of new generating resources and merchant transmission projects to the PJM grid.

5/18/2012

DEMAND RESPONSE

Demand response—the ability of retail consumers to respond to wholesale electricity prices—is integrated into PJM Interconnection's wholesale electricity markets, providing equivalent treatment for generation and demand resources. Retail customers have the opportunity to participate in PJM's Energy, Capacity and other markets and receive payments for the demand reductions they make.

PJM is working to broaden the opportunities for electricity consumers to respond to wholesale prices and grid conditions.

Consumers have the opportunity to manage their electricity use in response to conditions in the wholesale market. They can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. Common examples of reductions are turning up the temperature on the thermostat to reduce air conditioning or slowing down or stopping production at an industrial facility temporarily.

Some industrial customers with backup generation might use their generators to meet a portion of their power needs during peak periods, enabling them to draw less from the system and reduce demand on the grid.

Even though wholesale electricity prices fluctuate hourly, retail consumers generally pay electricity rates that are based on average electricity costs. This means that they don't see the changes in wholesale prices and don't have the opportunity to react to them. Without clear price signals, consumers have no incentive to reduce their usage when wholesale prices are high.

Giving consumers the ability to "see" wholesale prices and react when prices are high can help minimize the impact of price spikes, reduce the need for expensive peaking generating capacity and help hold down energy prices overall.

The choice to participate in demand response is voluntary. But, participants must meet certain requirements in order to qualify for payments for

reducing their demand for electricity. Demand response does not include reductions in electricity use that follow normal operating patterns or behavior.

The following summarizes how demand response works in PJM.

Qualified PJM market participants who act as agents, called Curtailment Service Providers (CSPs), work with retail customers who wish to participate in demand response. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The allocation of the payment from PJM to the CSP and the retail customer is a matter of private agreement between them.

A CSP can help a customer identify opportunities and determine• the needed equipment and systems to benefit financially from demand response participation.

When locational marginal prices (LMPs) are high in PJM's Energy Market, economic demand response provides an opportunity to reduce electricity consumption and receive a payment. Participants have the choice of a day-ahead option or a real-time option.

In the day-ahead option, a CSP's customers can offer—in advance of real-time operations—to reduce the amount of electricity they will draw from the PJM system. If the offers are accepted, they will receive payments based on the day-ahead LMPs for the reductions. In the real-time option, a CSP helps customers reduce their usage voluntarily during times of high prices and receive payments based on real-time LMPs for those reductions.

Emergency load response compensates retail customers who reduce their usage during emergency conditions on the PJM system. The voluntary energy-only option compensates retail customers who choose to reduce their usage voluntarily during emergency conditions.

In PJM's Reliability Pricing Model capacity market, both demand-response resources and energy-efficiency resources have the opportunity to participate. They can receive payments for being ready to reduce their electricity demand or for implementing energy-efficiency measures.

The capacity market helps keep the lights on. It ensures that when electricity usage is high, there are enough resources available to meet the demand at all times. Those resources—generation as well as demand resources—enable electricity providers to have enough power to be drawn from when needed to meet the demand instantaneously.

Demand resources, through CSPs, can bid demand reductions into the market. Capacity is obtained three years in advance. For example, the capacity auction held in May 2012 obtained capacity for the 2015/2016 delivery year.

The ability to call on demand reductions gives system operators greater flexibility in managing the grid during summer heat waves and other challenging conditions. There are three separate opportunities for demand response in the RPM capacity market, with differing requirements.

In the limited product, customers commit to reducing their load at the direction of PJM during emergency conditions up to a maximum of 10 times during the summer months. In the extended product,

the number of interruptions can be unlimited during six months (May through October) of the year. In the annual product, an unlimited number of interruptions can be called during a delivery year, which runs from June through the following May.

A total of 15,755 megawatts (MW) of demand and energy-efficiency resources are committed as capacity resources for the 2015/2016 delivery year. The PJM region has more committed demand response resources than any other organized wholesale electricity market in the country.

PJM also enables demand resources to participate and submit bids for reductions in the Synchronized Reserve, Regulation and Day-Ahead Scheduling Reserves markets.

PJM's eLRS eTool provides CSPs, as well as electric distribution companies and load-serving entities, with an online tool for processing the registration of demand resources and demand reduction activity and transactions in the PJM markets.

PJM's goal is to see demand response fully integrated into the retail market. That will happen when a large number of retail electric customers, including homes and small businesses, have access to demand-response options. PJM is working with state commissions and other stakeholders to support that goal.

7/5/2012

RFP AND CONTRACT REQUIREMENTS

[PD-24]

SECTION	REQUIREMENTS
RFP, § 2.1(a)	Supplier must construct, own, operate, and maintain a new plant
Preamble	Supplier must offer to supply Capacity and Energy into the PJM market from the plant
Contract, § 2.6(d)	Supplier must participate in the BRA, the Day-Ahead Energy Market, and Ancillary Services Market
Contract, § 3.2(a)	Supplier must participate all PJM Markets including the BRA, the Day-Ahead Energy Market, Real-Time Energy Market and the Ancillary Services Market
Contract, § 3.2(b)(2)	Supplier must have the plant offer and participate in the Day-Ahead Energy Market, Real-Time Energy Market and Ancillary Services Market
Contract, § 3.2(c)	Supplier represents and warrants that the plant will be capable of fully participating in PJM energy and capacity markets

Contract, § 3.2(d)	EDCs are entitled to CPV's revenues from sales energy and capacity

Source: Case No. 9214, Notice of Approval of Amended Request for Proposals, Dec. 8, 2011

RFP AND CONTRACT REQUIREMENTS

[PD-25]

SECTION	REQUIREMENT
Contract, § 6.2(a)	No payment during any period in which the Supplier has not been selected to provide capacity in PJM's BRA
Contract, § 8.1(c)(3) & 3.1(e)	Failure of Supplier to participate in the capacity and energy markets will constitute a default
Contract, § 13.7 Exhibit G	Price that supplier receives under the contracts is contingent on quantity of capacity and energy supplied to PJM markets
Contract, § 3.2(d)	PSC can order EDCs to "take title to the Supplier's and 4.1(b) electricity products

Source: Case No. 9214, Notice of Approval of Amended Request for Proposals, Dec. 8, 2011

FILED
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OFFICE OF THE CLERK

Nos. 14-614 and 14-623

IN THE

Supreme Court of the United States

W. KEVIN HUGHES, ET AL., *Petitioners,*

v.

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

CPV MARYLAND, LLC, *Petitioner,*

v

PPL ENERGYPLUS, LLC, ET AL., *Respondents.*

On Writ of Certiorari to the United States Court of Appeals for the Fourth Circuit

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JOINT APPENDIX VOLUME II

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NOTICE

The following documents are omitted from the Joint Appendix. They are found in the Petitioner's Appendix to the 14-614 Petition For A Writ Of Certiorari at the following pages:

PPL EnergyPlus, LLC v. Nazarian, 753 F.3d 467 (4th Cir. 2014) (opinion) 1a

Order No. 84815, *In re Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, 297 P.U.R.4th 336 (Md. Pub. Serv. Comm'n 2012) 29a

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.,

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 4, 2013

DAY ONE TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman,
Esquire Larry F.
Eisenstat, Esquire

* * * *

[18] THE WITNESS: L. Gene Alessandrini, L, Gene, G E N E.

[19] Alessandrini, A L E S S A N D R I N I.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. MEYER:

Q. Mr. Alessandrini, thank you for being with us this morning. Could you please state your employer?

A. PPL EnergyPlus.

Q. And what is your current position at PPL?

A. Senior vice-president of marketing.

Q. Can you describe for the Court your educational background briefly, please?

A. I graduated from Villanova University in 1986 with a bachelor's degree in electrical engineering. I graduated from the University of Delaware with an executive MBA in 1996.

Q. And what positions have you held at PPL?

A. I was hired to PPL in 2006 where my original position was director of marketing.

In 2007, I was promoted to general manager of marketing, with the goal of continuing to build and grow out our wholesale origination team.

In 2008, I was promoted to senior vice-president.

In 2009, PPL Energyplus opened a retail energy business for service in the Mid-Atlantic region.

In 2011, PPL EnergyPlus expanded its analytical capabilities and the fundamental and portfolio analysis teams [20] and the business instructor analysis teams were removed under my organization.

Q. Can you describe your current responsibilities as senior vice-president of marketing?

A. That is correct.

Q. Can you describe your responsibilities?

A. Sure. There are three business groups that report to me. The first is wholesale origination. Wholesale origination is the process of bilateral transactions between wholesale market participants. Our customers are typically financial institutions, independent power producers, municipalities, cooperatives, investor utilities, and retail energy providers.

In that marketplace, we transact with counterparties in the purchase and sale of energy and capacity and related products.

The second team is our retail energy business. That business sells energy commodities to commercial end users. We have a C & I business, commercial and industrial business in the Mid-Atlantic region including Pennsylvania, New Jersey, Delaware, and Maryland.

We also serve residential customers in Eastern Pennsylvania. Again, that business transacts capacity and energy to commercial end users and residential customers.

My third business group is the analytics team. There are three analytics teams that report to me. The first is [21] business analysis. Business analysis is the team that performs performance analysis on the transactions the marketing organization does.

The objective is to understand how those transactions and the value of those transactions may change over time and how we modify our portfolio management of those transactions in the marketplace.

The second team is our structural analysis team. The structural analysis team determines pricing and valuations of products. So as I mentioned earlier, our customers being investor run utilities or independent power producers, municipalities, cooperatives, retail energy suppliers, when they come to us with their product, the wholesale origination team and the structural analysis team sit down and determine the value of that product or the pricing in which we engage the counter-party.

The third team is the fundamental and portfolio analysis team. The fundamental team is responsible for developing forward market prices. In that process, they go out and analyze commodity markets, fuel inputs, and forward capacity to energy prices.

They gather information and market intelligence, then use internal tools to develop our view of where forward energy and capacity prices will be.

In addition to that team, we have a portfolio [22] analysis team, whose primary responsibility is to take those forward energy prices, look at our portfolio and determine and forecast revenues, costs, and gross margins related to the portfolio, and identify potential changes to our portfolio, what fuel inputs we may need, how much procurement of fuel we may need to

do, how do we expect our generation to run, and how do we think the risks are within our portfolio both financial and physical.

Q. To put this in context, can you describe the nature of PPL's business activities?

A. Sure. PPL has four primary business segments. Three of those business segments are regulated utilities. The first is in the United Kingdom, Western Power Distribution, which is a distribution company that has 1.—excuse me, 7.7 million customers in the United Kingdom.

We have a second regulated utility that serves Kentucky and small portions of Tennessee and Virginia. That is Louisville Gas and Electric and Kentucky Utilities, which serves over one million electric and natural gas customers.

Our third regulated utility is PPL Electric Utilities, which is based in Allentown, Pennsylvania, and serves Eastern Pennsylvania, and has over 1.4 million customers.

The fourth business segment is PPL Energy Supply. PPL Energy Supply is the generation and marketing and trading [23] company of PPL Corporation. We have generation assets in Montana and Pennsylvania. We also have market and trading operations in Montana and Pennsylvania. The position of PPL EnergyPlus, which is in the PPL Energy Supply Organization, manages the portfolio of our generation assets and provides sales and purchases of energy commodities to hedge the financial positions of assets.

Q. And what portions of PPL operate in the PJM region?

A. PPL electric utilities, which is the transmission and distribution within PPL Corporation, operates within the PJM market from a transmission, distribution standpoint. And PPL Energy supplies Pennsylvania assets, which amount to over 9500 MW of generation operates, that's generation power plants in Pennsylvania and inside the PJM marketplace.

Q. Can you describe for the Court what PJM is?

A. PJM is a regional transmission organization, whose primary responsibility is to match the planning and operations of the transmission system, which is a regionally interconnected grid that allows power or electric production to be transported across the entire region.

It also manages energy markets, both capacity energy and service markets, which look for the most economic dispatch of those generation resources to serve the load across the region.

Q. I want to show you an exhibit that's been marked as

* * * *

[33] provide the parent corporation with the financial certainty.

Last, our last components of PPL EnergyPlus, it's our responsibility to work with a cross-functional team within PPL Energy Supply to provide analysis and market intelligence on current forward market prices and then using our internal tools to determine scenarios and other events, which would create new forward prices or scenarios that allow us to determine investment decisions for current assets and new assets.

Q. Let's—focusing for a moment on the generation asset component of what you just described, I'd like to direct your attention to plaintiffs' demonstrative 11.

Do you have that?

A. Yes, I do.

Q. What does this map depict?

A. This map represents PPL's generating plants in PJM. So you'll see the green dots, which represent each of PPL Energy Supply's generation assets in Pennsylvania and at the PJM marketplace.

In addition, you'll see that the colored section in aggregate represents the MAAC region, and then EMAAC represented in a lighter blue color, represents the utilities in the EMAAC region, which are PSE & G, New Jersey Central, Atlantic City Electric, PECO Energy, and Delmarva Power.

And then in the bottom again slightly different color shade of blue is the SWMAAC region, which includes the [34] utilities of BG & E and PEPCO, and broader in the gray area, it shows the RTO as an aggregate of all that together.

Q. So IF I understand correctly, you've described MAAC as encompassing everything that is in some shade of blue?

A. That is correct. MAAC is the entire region that's represented by those three shades of blue.

Q. So SWMAAC and EMAAC depicted separately are subregions part of MAAC?

A. Yes. EMAAC and SWMAAC are subregions of MAAC.

Q. And does this—and this map depicts the PPL generating facilities that are located in PJM?

A. Yes, that is correct. The green dots with the names represent the generating facilities owned by PPL EnergyPlus in Pennsylvania and as part of the MAAC region.

Q. So now turning to the marketing business, which was part of I believe what you were describing a moment ago, PPL EnergyPlus is responsible for selling the output of these generating facilities within PJM?

A. That, that is correct. PPL EnergyPlus is responsible to manage the portfolio of assets, which they do through offering them into the PJM capacity market and the PJM energy markets.

In addition to that, they are responsible and in aggregate to also do bilateral transactions, which is the sale of energy capacity and related products between two counter-parties.

[35] We also forward hedge the generation assets, which is the sale of those output or the forecasted output, years forward to provide financial certainty for the corporation.

And then we also participate in the evaluation and analysis of investment decisions for existing assets and new assets.

Q. I want to come back and talk about some of those subjects in a bit. But before we do that, we're all here today because PPL and other companies have filed this lawsuit against the Maryland Public Service Commission.

Could you describe from your perspective what PPL is complaining about here?

A. The primary reason for our complaint is that the Public Service Commission of Maryland has ordered the electric utilities of Maryland to enter into a pricing—price guarantee contract for a new generator.

Q. Why is PPL complaining about that order?

A. Well, simplistically, you know, it goes against our view of how markets operate, and it prevents the market from operating correctly. So more details would be that, one, we believe it interferes with market operations as they are intended in the PJM marketplace.

Second, we believe it specifically requests a unit in SWMAAC of a specific asset type of a specific fuel type and specific delivery period where the PJM marketplace is blind to [36] those requirements, it allows based on the economics of the facility with none of those limitations to be determined by market.

Third, we believe that the result of this activity will impact the market from a standpoint that it will potentially lower prices than it would otherwise be. It provides uncertainty in a company where the market's ability to forecast forward prices and the impact of those forward prices.

It may lower prices, as we discussed, and it provides risk, particularly for a company like PPL, in understanding what those potential outcomes are and what risk decisions we need to make as we consider investments going forward.

The activity of Maryland, New Jersey, really do require us to take action because of the fact that it impacts the market and prevents it from operating the way it was intended.

Q. Are you saying that PPL filed this lawsuit because it opposes new generating facilities coming into the market?

A. No, not at all. PPL welcomes competition. And all my communications with both the regulatory agencies, Public Service Commission, and legislators, always says that what PPL looks for is a level playing field and the opportunity to compete. And if given that level playing field and the opportunity to compete, then we succeed on our own merits.

So this is not about the addition of new generation, [37] it is about allowing the market to operate as intended and allow it to do so without interference by other market participants.

Q. You're aware that CPV, Competitive Power Ventures, and their subsidiary CPV Maryland turned out to be the winning bidder in this Maryland process, and CPV has intervened as a defendant in this case?

Does PPL oppose CPV's proposed project coming into the market?

A. Not at all. Very similar to my statement earlier, you know PPL welcomes competition, and this is not an issue of the CPV plan but more of an issue related to the order which requires the investor-owned utilities in Maryland to enter present guarantee contracts and is not related to the CPV

Q. Okay. So let's transition to another topic.

Drilling down in a bit more detail on PJM and its wholesale markets, which you've described in summary fashion a bit earlier, how does PJM as an RTO facilitate wholesale transactions?

A. So PJM manages in its entirety an inter-connected region. And the two primary markets per se

that we participate in, and they use to manage that marketplace, is the energy and capacity markets from a wholesale energy standpoint. The capacity market, as we mentioned earlier, is defined as RPM, and they procure capacity three years forward to ensure reliability for [38] the system to make sure there's sufficient capacity for load at the time that it is needed.

Second market is the energy market, where they dispatch generation resources on an hourly basis to ensure that cost effective dispatch is available to serve energy or the load of the customer every hour of the day.

In addition to the wholesale energy markets, they also are responsible for the transmission system, as we've discussed. The transmission system is basically the maintenance and operations of the system on a daily basis to ensure reliability of electricity delivery across the region.

And it's also responsible for the planning, which we call the expansion planning process, where they on an annual basis evaluate what new transmission or what improvements in transmission are necessary to meet the requirements of the load in the future.

So that's the general overview of the PJM market.

Q. Okay. You mentioned in the course of your answer RPM, I'm not sure you've used the full term for that acronym.

A. RPM is defined as the Reliability Pricing Model, and it is the market or the mechanism that PJM utilizes to procure or forward capacity for the needs of the region.

Q. So you've summarized that PPL participates in these wholesale energy capacity markets, including on a bilateral basis. Can you provide some examples of the kinds of bilateral [39] transactions in which PPL participates?

A. Sure. PPL EnergyPlus and PPL Corporation, as I mentioned earlier, sells and procures energy in the wholesale and retail energy markets.

On the wholesale side, our bilateral transactions are typically with retail energy providers, who use that energy and capacity to sell to end use customers. It could be with investor-owned utilities. And in the case of Maryland, we do provide power to the Standard Offer Service, where we procure and provide wholesale power, which the investor-owned utilities provide to their retail customer.

We also service municipalities, cooperatives, and boroughs, and these entities typically look for long-term power. And in those cases, we provide energy and capacity.

In addition to the sales that we provide across many market participants. We also procure or purchase energy capacity. In those markets, we work with independent power producers, and we work with project developers to purchase or procure the output of those facilities, either existing or new, and we do through either a tolling agreement, which is the physical delivery of fuel, and the generation dispatch of electricity, or we also do it with the procurement of energy and capacity in which we recently did with an eight year product from an existing resource in Pennsylvania.

So we're very active in both the procurement as well [40] as the sale side of energy commodities within PJM.

Q. So when PPL participates in a wholesale sale of energy and capacity of the sort you've described, that's not in the capacity auction or the day ahead PJM market, under what authority is PPL able to make that transaction?

A. PJM—PPL EnergyPlus has a market-based rate authority under FERC, which gives us the ability to buy and sell electricity with two willing counterparties at arm's length and at market-based rates.

Q. Are there geographical limits as to where PPL is able to sell energy and capacity in the manner you described?

A. No. There are no geographical limits for our ability to sell energy and capacity. So in the bilateral market, as we walked through a second ago, PPL EnergyPlus works with its customers both wholesale and retail to understand what their energy needs are and the team evaluates those products, determines pricing, and where the requests for locational delivery of those products is different than the PPL generation assets, the origination team and the structure analysis team will evaluate those price differentials either in the capacity market or in the energy market and place those price differentials in the total valuation and the price that we provide the customer.

Q. You mentioned briefly I think that you have made—PPL has made sales of energy and capacity from its assets in [41] Pennsylvania into Maryland. Is that correct?

A. That is correct. PPL Energy provides both wholesale through the Standard Offer Service and retail to end use customers throughout the State of Maryland and all other service territories of BGE, Delmarva Power, and PEPCO.

Q. Can you give some specific examples of those kinds of transactions?

A. Sure. We have retail customers, which are again commercial and industrial end users, where we provide energy capacity and ancillary services for a period of six months to over two years.

We provide standard offer service, which is a forward requirements product, also which includes energy capacity and ancillary services.

And those terms range from three months to two years.

In addition, we participate actively in RFP's across PJM, but also within Maryland where we provide offers to market participants for terms of one year to ten years for energy and capacity across the region.

Q. Taking your last example of participation in RFP's, who are the counter-parties to which PPL would be selling in that sort of transaction?

A. Most RFP's are requested by either a municipality, cooperative, or a borough, or other forms of public power, who look to procure through what I would call a layered approach of [42] having energy and capacity for the long term.

In addition, we do have some commercial and industrial customers who also look to procure energy for the long term.

Q. In the standard offer service setting that you described, who are the counter-parties in those transactions?

A. The electric distribution company, or the investor utility, as sometimes called in Maryland, are the buyers of the SOS service or Standard Offer Service.

Q. You mentioned in describing responsibilities and PPL's participation in the PJM region and markets that PPL analyzes investment decisions within the market.

Could you describe how PPL does that?

A. Sure. PPL is continuously evaluating on an annual basis our investment in our assets, and we basically go through three types of analyses.

The first is existing facilities and investment in those facilities to maintain operations.

The second is expansion of an existing facility or as called in our industry, uprates.

And the third is new generation assets.

So as I mentioned earlier, we put together a cross-functional team, across PPL Energy Supply, and where PPL EnergyPlus sits down, looks at current forward market prices, understands the fuel inputs. We also have to develop price for [43] fuel inputs, nuclear, coal, natural gas, petroleum.

We look at generation availability and potential new supply and retired supply. We look at the cost of operating those facilities, and we look at load where it currently is and what we forecast low growth to be, and from that we assess what forward prices may be,

what potential revenues are, gross margins and return on investment.

So in aggregate, that's the process we go through. When I look specifically at examples of what PPL has done since 2007 and since the Reliability Pricing Model has gone into effect, from an existing resource standpoint, we've invested over one and a half billion dollars in four coal facilities of Montour and Bruner Island, and in that investment, we made environmental investments so those units could meet their Environmental Protection Agency's requirements.

Our second example with respect to unit expansions or uprates PPL has invested over $400 million in our Susquehanna nuclear facility to provide over 200 MWs of additional generation capacity.

In addition to Susquehanna, we also have expanded our Holtwood Hydro facility in investing almost $400 million with approximately 120 MW expansion at Hollywood.

In addition to the new expansion opportunities, PPL on an annual basis evaluates not only its existing sites that have the ability to expand from a capacity standpoint, but also [44] look at other sites that are brought to us by other market participants.

We currently have the ability to build a new combined cycle facility at our Martins Creek facility, and we've evaluated, and I've gone through the beginning of a process to add a third nuclear unit at Susquehanna, which we call our Bell Bend site.

Q. Could you describe in the course of this evaluation of potential investments what role market price levels plays?

A. Market price levels are obviously a very important part of the analysis. So as I mentioned a few minutes ago, PPL EnergyPlus's team looks in aggregate of where market prices currently are today. We look at market information. We work with industry leads and other sources to understand where we believe fuel input costs will be from a natural gas, coal, petroleum, and nuclear standpoint.

Again, we look at where we see supply and demand, where supply is the generation resources in the PJM marketplace and demand is the demand of customers to use load.

So in aggregate, we look at all those components as well as the cost of the generation and the cost to maintain it. And then through that aggregate analysis, we then develop forward market prices that allow us to determine revenues and gross margins and contribution.

Q. And what forward market prices are you looking at when you [45] perform that evaluation?

A. So today we look at current market prices, which are for electricity going out for a period in today's market a period of approximately three years.

In addition to that, those electricity prices, we look at forward fuel inputs, as I mentioned. Those fuel inputs are primarily driven by the natural gas market, which is liquid and transparent through approximately 2020.

Then we look at the other fuel inputs being coal as the primary source and oil. And then in aggregate, we look at all those four curves and then we take those curves into our internal tools, and we use those internal tools to determine where we think prices

would go and develop our curves for a period of 5 to 20 years.

When we develop those forward prices, we do so not only with the input of the market and resources from the market, but also in developing our own approach to where we think prices may be and how supply and demand generation type and generation cost will change over time.

Q. So I think the first kind of price that you mentioned in your last answer was electricity prices. Does that include both energy and capacity?

A. Yes. To be more clear, electricity prices in our case do include what we consider the three primary sources of revenue for our assets, and that would be energy, capacity, and [46] ancillary services.

Q. Now, the capacity component of prices, the capacity price comes from where?

A. So currently today, we use the Reliability Pricing Model as our data point for our capacity prices. So we have historical prices up and through last year's auction, that take us through May of 2016.

And then more importantly to us is really the framework of how capacity develops. So it is the market structure that PJM has in place as the Reliability Pricing Model that drives our ability to determine forward prices.

So where interference occurs in that market, it makes it more difficult for us to forecast, but the key of RPM is not is the one-year price, it is the data points created by multiple auctions, and it is the ability to use the RPM structure to be able to forecast prices. That way, we can make intelligent investment decisions.

Q. So if I understand correctly, PPL does not simply look at the one-year price set by the most recent RPM auction that is for delivery three years ahead, it looks beyond that?

A. That is correct. So we consider the one-year auction results as one data input of many data inputs that we use to make those investment decisions and market decisions. And again it is the structure of RPM, it is that mechanism that is more critical to us, because it allows us to have the ability [47] to forecast forward capacity prices. So that way, we have the ability to put that in our model to determine economic returns.

Q. So how have the Maryland PSC's orders at issue in this case, those we touched on earlier, affected how PPL evaluates investment decisions in PJM?

A. The PSC's order has really impacted our ability to provide some certainty, all right? So the key for us is the ability to forecast. So whenever we make an investment decision, it doesn't matter if it's maintaining an existing facility, if it's expanding a facility, or if it's building a new generation asset.

Our ability to determine economic value is driven by the ability to forecast forward energy capacity and ancillary services revenues. So the PSC order impacts our ability to forecast. It creates uncertainty in the marketplace, in the market structure, and regulatory risk that we have to consider for any future investment that we look to make.

Q. Okay. Let's shift gears a bit. PPL monitors the PJM marketplace with respect to the activity of other market participants; does it not?

A. Yes. We are very active in the market from a wholesale standpoint and from a retail standpoint with the objective of making sure we're well-informed of what's happening in the marketplace, taking market information, and for our decision-making, and then also to make sure using market [48] resources to provide a broad overview of the industry where prices may be going, what may be happening so we can make good decisions.

Q. You've described already for the Court PPL's—some of PPL's investment activity in PJM since the institution of this RPM Reliability Pricing Model in PJM.

How have other investors responded to those capacity market price signals?

A. RPM, in our opinion, has been successful, and it's been successful because new resources have been added in the capacity market, and those resources are diverse in nature, meaning they are delayed retirements of assets. They are uprates, as we talked about, in generation assets. They are the addition of demand response resources. They are the addition of energy efficiency. And they are the addition of new generation.

So the market has responded to the RPM price signals and has responded to the need for new supply in a cost effective way, you know, broadly across the region.

Specifically, you know, PPL Energy Supply has added over 500 MWs of new resources, as I've outlined, with those uprates and other improvement. So we believe the market price signals are working. We think the market is adding capacity resources. We believe it's doing so cost effectively, and in any market, it is

typical you start with the lowest hanging [49] fruit and you work your way up the cost chain. And the market is effectively providing resources based on that philosophy.

Q. I'd like to direct your attention to plaintiffs' demonstrative number 17

Do you have that?

A. I do.

Q. What does this map depict?

A. This graphic map represents generation resources, and I'll walk through each one of those as we—if I start at the top right corner.

Next, in the top right corner of the text in some of the legend or table there, there are state-sponsored generation resources, which are a burgundy triangle. I'm sorry, burgundy diamond. And they represent the New Jersey and State of Maryland state-sponsored generation resources.

And then I'll go through the next three as well, which are not state-sponsored. So the green circles are assets that are in operation, and they again are being driven by the market providing the appropriate price signal in the appropriate market-based activity, those resources, some examples are the York Energy Center in Pennsylvania, the Longview Coal project in West Virginia, and as I mentioned earlier, the PPL Susquehanna uprate.

The yellow squares being projects that are under construction, and some of them have cleared the BRA, and for [50] example, those are the Garrison project in Delaware, the LS Power project in New Jersey, and the PPL Holtwood expansion, which I mentioned earlier, as well as our hydro facility.

Number four, which is the orange triangle, is projects that are currently in the discussion phase or in the PJM queue looking to be developed. And these are projects that again represent a market's response to where forward energy capacity and ancillary services revenues warrant investment in new generation assets across the PJM market.

So these assets, you know, are ones that private equity and other equity investors and other market participants have interest in. And, you know, we expect that some of these assets will be built. Not all assets, as we all know in the PJM queue actually get built. But most of these assets come to market. They're evaluated by the marketplace. They're evaluated by investors. They're evaluated by market participants, vendors and so on.

And those that make the most economic sense and are achievable actually get built as time has warranted from supply and demand and by market-based activity.

MR. KLEINMAN: Your Honor, I'm going to make an objection for the record about this line of questioning. We didn't receive this demonstrative until late last night. While we've been understanding with each other by late exhibits, et cetera, unless the witness is able to either lay a foundation [51] for where the data came from, and there is no indication of where this data came from, and unless the witness can testify only on his personal knowledge, he's offered, repeated in his last answer about what other investors are thinking, which is the nature of an opinion for which there's been no pretrial disclosure opinion testimony.

I would object to the line of questioning. We've already had in this case one instance in which the

plaintiffs gave us a report of an expert which purported to tell us the total number of MWs that were going to be constructed in Maryland. We had a couple days that we took that apart in deposition. It didn't survive.

And so I think this is deeply prejudicial unless we know what the basis for this is. We have the information in front of us and would like to have a fair opportunity.

THE COURT: Are you complaining about the orange triangles, under development?

MR. KLEINMAN: Yes, among other things, Your Honor. I mean, I don't know what they mean by under development. Unless the witness can say that he has personally talked to the people who are behind each of these developments and he's going to be able to tell us on cross what it is they say, and the extent to which they're under development, does it mean that they have a lease on some property? Does it mean that they have invested real money? Does it mean—

[52] THE COURT: I get the point, Mr. Kleinman. Let's see. You're not saying that this is unreliable in terms of what's in operation, or what's under construction, or what state-sponsored, which presumably is the facility at issue here, and I presume the three at issue in the New Jersey case?

MR. KLEINMAN: Well, to start at the bottom, I've already addressed under development. To talk about in operation, if you look in the lower left-hand corner of exhibit 11, or demonstrative 11, Longview, this is not set as a diamond as though it were state-sponsored. But we have an understanding of which we had the time we could go and run down that the

Longview plant benefited from an economic development working with state, with local.

THE COURT: I don't see we need to have a great deal of time devoted to this. The basic objection, Mr. Meyer, is, as I understand it, the accuracy of the prediction nature of these orange triangles, you can tell where that comes from, and as I understood what he said was in operation was its function.

And Mr. Meyer, if you want to tell us where he got the information on this chart, you can do that.

MR. MEYER: I'd be happy to explore it with the witness and have him explain.

THE COURT: Let's find it out. I was trying to see what, because, again, I don't know that we're at the heart of the dispute here, what is in dispute, but I gather, Mr. Meyer, [53] that the three state-sponsored places in New Jersey are the ones at issue before the judge in New Jersey, correct?

MR. MEYER: Those are the three projects that received the LCAP awards in New Jersey, yes, sir.

THE COURT: And the other one is the one at issue here, the one in Maryland. All right. Why don't you—let's just find out where the data comes from, so we can move past this point.

I mean, the point just seems to be is that under the existing system, things are happening. There has been generation. But go ahead.

MR. MEYER: Precisely the point, Your Honor.

BY MR. MEYER:

Q. So Mr. Alessandrini, referring first to the in operation, the projects that are showing in the green

circle, could you summarize what the information shown on this chart is based upon?

A. The green circles in operation assets represent generation assets that we know of, that have actually come in operation, into the PJM marketplace at the time, and MW amounts that are shown here.

As I mentioned as part of my testimony, that the PPL Susquehanna uprate occurred in 2011, is where PPL Energy Supply invested in increasing MW capability of its nuclear assets. So all these green highlighted squares are assets that either have [54] been expanded or they are new assets that have been put in place in the PJM marketplace at the time designated here.

Q. Okay. Now, referring to the under construction or cleared BRA category, the yellow squares, what is the information in that category shown on this chart based upon?

A. It's shown assets that have cleared the PJM Base Residual Auction, and those assets are under construction.

Specifically, the PPL Holtwood expansion again is a PPL Energy Supply investment in expanding the capability of our hydro facility in Pennsylvania. That asset is under construction and is expected to be completed by the end of 2013.

In the case of LS Power and Garrison, which is a Calpine project, those are two assets that cleared the last PJM RPM auction and are under construction for service for the 2015 period.

Q. Now, referring to the under development category, let me ask you first, the projects that are

shown on this map, what was the basis for their inclusion on this map?

A. Two primary reasons. The first primary reason are these are assets that are in the PJM queue that represent generation assets that are looking for the opportunity for development and construction and operation in the PJM marketplace.

The second is a majority of these, if not all, are all assets that we have talked to the counter-parties in [55] evaluating the projects to determine if it made sense to provide an offtake to those agreements.

So as we mentioned before, our goal is to be active and engaged in the marketplace. And that activity allows us to continually evaluate our buy, build, and contract scenario, which I can discuss at length.

And the objective is always to make sure we're aware of where market activities are happening and have a good understanding of how the market is going to perform and how it's expected to perform.

So these orange triangles represent generation assets that we have had market activity with amongst many other market participants to determine if we will be interested in a contract, which would purchase the power being both the energy and the capacity, or energy only, depending on the project, so that they could develop and finish that project.

Q. So to be clear, you're not saying that the orange triangles will necessarily eventually enter the market and begin construction, are you?

A. No. That is not the intention. The intention is to demonstrate that there is market activity, and that is both from a project developer standpoint and from a market standpoint.

And as we spoke about a few minutes ago, the intention of the market is always to start with the low hanging [56] fruit, which is typically the most economical, which as history has shown in RPM, has been more demand response, energy efficiency, delayed retirement and uprate process.

And then as you move through the process, to balance supply and demand and based on economics, new generation gets added, and it's based on willing market participants participating in that process.

In this case, these are all market participants who have the desire to build an asset, and it actually will be the marketplace that will determine if they're economic and they can get built based on what their actual construction costs are, ability to finance are, and what the billing prices from the marketplace to enter into agreements for these assets.

THE COURT: All right. Let's try and put this in perspective of what's critical and what isn't.

This is offered—first of all, the essence of the testimony is how does PJM work, and that it's working.

And secondly, these things are places for potential I guess facilities that have enough reality that PPL is willing to spend time talking to people to see if they can work out a deal.

And it doesn't mean that this is going to happen. So I'm going to overrule the objection, I take it what I've just said, and let's move on, Mr. Meyer.

BY MR. MEYER:

[57] Q. Thank you, Your Honor.

I do want to direct your attention to one specific green dot on this diagram, the York Energy Center. Do you see that dot?

A. Yes, I do.

Q. It looks like it's located sort of just north of the—is that the Maryland border there?

A. Yes. Looks like it's located just north of the Maryland border.

Q. And I'd like to show you plaintiffs' demonstrative 43 projected on the screen here so we don't have to look at two things at the same time in your binder.

Could you describe what the York Energy Center is?

A. The York Energy Center is a combined cycle natural gas facility located in Delta, Pennsylvania, which is approximately or slightly more than a mile straight line to the Maryland border. I'm sorry.

Q. I'm sorry. I may not have heard you say, who operates that, also?

A. Calpine operates the facility. They actually acquired that facility from Connective Energy Supply back when they purchased the supply business of PEPCO holdings.

Q. Now, referring to the list of projects that you talked about referring to the prior demonstrative, and but not—I'm not speaking specifically as to any one or group of them, [58] generally, how are those projects, how are any projects of PJM able to come into the market without a state-ordered long-term contract?

A. New generation is added, you know, based on the ability for that generation to prove economic. Simplistically, in our cases where we work with

market participants, those market participants bring to us projects that we evaluate based on them outlining to us the project needs from a financial standpoint.

And again we look at what we call physical tolling agreements, where PPL energy supply will come in and provide physical fuel to the generation resource. We would dispatch the generation and receive the production from that asset.

In those arrangements, we sit with the counter-party to determine what we determine the value of those assets are. We work with the counter-party to understand the project, the technology, the location, any advantages it may have from either a fuel or transmission standpoint, and we run through the economics to determine if those projects make economic sense.

The marketplace today is demonstrating that the projects do make sense, and therefore these projects are being developed on a one-by-one basis. And we believe that will continually be developed on a one-by-one basis.

Q. And what specific experience does PPL have with respect to [59] the question of the ability to finance these projects in today's—or in recent PJM market conditions?

A. Sure. PPL EnergyPlus signed an agreement with Longview in where we provided a hedge for the Longview facility, which they were able to utilize as part of their financial package and therefore able to get the project built and consortium with a group of others to have that project built and actually operating as it's demonstrated on the prior demonstrative.

Q. And has PPL evaluated financeability in connection with other projects?

A. Yes. In most of these orange triangles, we are in discussions with the counter-parties to determine both their economics and our economic needs to make sure that we have a fair assessment of our risk and value, and they have the ability to deliver the project if we go down the path and sign the agreement.

Q. So how—does all this activity that you've described suggest that the Maryland and New Jersey regulatory actions won't get in the way of all this new investment?

MR. KLEINMAN: Objection, Your Honor. He's asking for an opinion.

THE COURT: I think I'd sustain that objection.

Q. So in PPL's evaluation of investment activity in the current marketplace, could you describe the impact of the Maryland and New Jersey actions?

[60] A. Yes. From PPL's perspective, the PSC order and the New Jersey activity creates uncertainty. As I mentioned earlier, it is important for us to be able to have a framework in RPM and in the energy markets to be able to forecast forward energy and capacity prices. And the entry of these generation resources through state price guarantees impacts our ability to forecast those prices, because it creates uncertainty, not market-driven solutions. And therefore it creates an additional risk that we have to consider when we make economic investments in power plants and generation assets.

Q. I'd like to direct your attention—

THE COURT: Before you get off of that, let me ask this, I can understand and eventually we'll get

into, it's not a good thing for you in terms of your economic valuation, but what do you mean by it creates uncertainty? It's there, and I don't see how it -- or at least help me understand why you say it creates uncertainty as distinct from saying it distorts the market, but at least we can see how it's going to distort the market.

THE WITNESS: That's a good question. So let me approach.

THE COURT: Thank you for that.

THE WITNESS: Approach it in two ways. I'll try to speak slow as I answer the question.

I'll approach it in two ways. So before the PSC [61] order and before the generation assets cleared the RPM auction, PPL's approach to the market was again to look at that framework.

So we have this RPM framework, which is expected to operate in a market-based environment. So therefore, when we look at that framework and forecast our views of where capacity prices would be based on supply and demand, that forecast is driven by an understanding of what is known, right?

So what was known prior to these orders was that market-based solutions would be entering in the market, and those market-based solutions would follow typical commodity market response, which as I've outlined today is you typically get your low hanging fruit, your most cost effective solutions, they're relatively easy, there's little entry, and you get a lot of participation. The example of that demand 'response, example of that is delayed retirements.

After that, you go to the next most economic in general terms, which would be capacity expansions,

right? That's easier to add additional MWs typically than it is to build a new asset.

So you have what I'll call relatively defined or predictable market framework. So the uncertainty is created when somebody adds this PSC order or the LCAP into the marketplace, and this is something that the market wasn't predicting.

[62] Not only does it distort the market where we are today, but it also creates an uncertainty of how things may look forward. Is there another regulatory framework that's going to distort the market and create further uncertainty?

So where we have had a relatively defined mechanism and framework, it has now been distorted by actual results but it creates a question mark how do you forecast going forward, because not only those assets impact or potential lower prices today or what future ones are out there that present the ability for us to forecast accurately to make those investments.

THE COURT: Let me see if I follow this.

We're now talking about uncertainty. You know, let's not get too much in New Jersey, but I'm sure the facts are a little bit different. But you now know what Maryland has done, and there's no uncertainty about that. We know what Maryland has done.

What your concern is that either Maryland will change its amount or that Pennsylvania will now get into the act, is that the uncertainty that's added, the fact that you now have to worry about—if they can get away with this, then we have to worry about legislative action in all of the 13 states.

THE WITNESS: Yes. I think that's a very good summary. The uncertainty that's created is not only to

your point, additional activity in Maryland, or other products and [63] activities in Maryland, but also activities across the PJM marketplace.

So when we look at investment, as we talked about, we look broadly across the interconnected region. When we look at new assets, we just don't look at Pennsylvania. We look at New Jersey. We look at Delaware. We look at Maryland. We look at Ohio and Illinois. So we are worried and therefore that uncertainty is much broader than just the Maryland activity.

THE COURT: Is this fair, I mean, I just want to be sure to understand this, so that if I used this crude way, if Maryland can get away with this, then Ohio's likely to do the same thing and Illinois's likely to do the same thing, and that's, I know that's going to be argued in another sense, but that adds -- the uncertainty that's added is we now have to worry about 13 state legislatures, and that if, again, just trying to get to your point, that if this does turn out to benefit Maryland at the expense of everybody else, then you can expect that everybody else is going to do the same thing so that you're going to face this in every state. Is that it?

THE WITNESS: Yes, that's an accurate summary.

THE COURT: Okay. Now, I'm not saying that's right or wrong, that's your position, and that's what you meant by uncertainty. Okay. Fine.

Mr. Meyer, I guess we should give the reporter about 10 minutes at this point.

* * * *

[71] the Catoctin facility back in the mid 2000s, the transmission constraint at that time was a west to east constraint. So, therefore, power had difficulty moving from western Pennsylvania, Ohio, Western Maryland, West Virginia into the SWMAAC territory. And the Catoctin was east of those constraints, so therefore it was deliverable into the Maryland region without limitation.

Q. I want to shift gears and ask you when PPL—excuse me.

When Maryland Public Service Commission issued its RFP order, the order requiring the EDCs to issue an RFP for a new generating project and so forth, did PPL review that order and consider whether to participate in the RFP solicitation?

A. Yes. PPL looks at most opportunities that enter the marketplace. So a team was assembled, and we reviewed the RFP, and it was determined for two reasons not to participate.

The first reason was that we did not have generation assets facility or location that was in SWMAAC and available to participate based on that requirement. As I mentioned earlier, our readily available sites were in Pennsylvania, where our existing facilities are.

Second reason for not participating upon review was that the RFP acted in a manner inconsistent with our market principles where we believe solutions for new supply and new generation assets should be market-based products.

Q. Has PPL or have you communicated with Maryland in

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND
NORTHERN DIVISION

CIVIL NO. : MJG-12-1286

PPL ENERGYPLUS, LLC,
Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, ET AL.,
Defendant.

March 4th, 2013
Baltimore, Maryland

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
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For the Defendants:

H. Robert Erwin, Esquire
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Ransom E. Davis, Esquire
Christine T. Asif, RPR, CRR

[2] PROCEEDINGS

(Afternoon session 3:20 p.m.)

THE COURT: Yes.

MR. ROBERTS: Your Honor, Richard Roberts, counsel for PSEG Power and would like to call as our next witness Mr. Ken Carretta.

THE CLERK: Please stand, sir, raise your right hand.

KENNETH R. CARRETTA,

called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself.

THE WITNESS: Okay. How's that?

THE CLERK: That's a little too close. That's much better. State your name and then spell your name for the record.

THE WITNESS: My name is Kenneth Carretta, that's C-a-r-r-e-t-t-a.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. ROBERTS:

Q Thank you, Mr. Carretta, and good afternoon. Mr. Carretta, who is your employer?

* * * *

[21] paradigm, we are going to try to be successful when we can.

Q Thank you, Mr. Carretta. The last thing I'd like to discuss with you is how Maryland's actions have effected PSEG Power's market participation. So me start with a broad question, how is PSEG Power's market participation effected by the Maryland RFP program?

A I would say in a couple of different ways. One way is it effects the way we look at investments or future investments in the PJM region. Because the program is an artificial distortion of the market, and inconsistent with what, you know, we would view as fair competition. It's kind of a deterrent for us to participate. And I would also add that it has also effected our ability to recover past investments that we made, which were made in reliance and with the expectation that there would be competitive markets.

Q Okay. To take those two in turn, how does the Maryland program hurt your ability to make new investments in the construction of generating plants?

A Well, as I think I said earlier, the only — the way we recover our costs, and the way we can make a return on any new investments is through the marketplace itself. So it's really important to us that there be a level playing field. Something like the Maryland program unlevels that playing field for us. And we are—it's—we're—our management is very concerned, very reluctant about putting large capital [22] expenditures into building a plant that is going to have to try to recover its costs through this unleveled playing field.

Q Could you provide a real world example of how the Maryland program has effected your investment decisions?

A Yes, I think I can. We've been considering and working on developing a new plant at our Seaborn site, a combined cycle plant, for several years that would replace older generators that are there now. We did consider placing a bid into the 2012 base residual auction for RPM, but we ultimately decided not to. And one of the main reasons, something that weighed very heavily on our decision not to participate, was our concern over the interference that we saw by the states in these competitive markets.

Q Now, turning to your second impact, how does the Maryland program hurt your ability to recover prior investments?

A Well, it puts into the bid stack, it creates a resource that wouldn't otherwise exist. And under the PJM structures that will tend to suppress the prices that would have occurred in a competitive market and in the absence of the out-of-market unit.

Q Well, you said it tends to, is there evidence that it has in fact done so?

A Following the last RPM auction, PJM prepared a series of sensitivity studies. And in one of those studies they simulated the impact of taking out from the bid stack what [23] would have happened if a plant very similar to the Maryland plant had not been constructed or put in the bid stack. And that exercise showed that the prices would have been about 27 and a half dollars per megawatt day higher than they actually were. If you do the math—in the region called MAAC, which is where all of our PJM assets are located. So if you do the math, given the number of resources that we cleared, for that particular year it had about a $90 million impact on us.

Q What do you mean by it had a $90 million impact?

A That if that unit had not participated in the auction, prices would have cleared higher. And as a result we would have received more revenues, about $90 million additional revenues from RPM. And this is—this is the kind of activity that, you know, is a concern to our—I mean, this kind of effect is exactly the concern that our senior management has, I think, and what they think about when they make investment decisions going forward.

Q So does this $90 million loss effect your investment incentives?

A Yeah, I think it does. That there's a concern by our management that they're unable to predict when states are going to take actions like this. And they're very reluctant to put—or make large investments in markets that can be disrupted like this.

MR. ROBERTS: Thank you very much, Mr. Carretta. I [24] have no further questions at this time.

THE COURT: Before we get to the cross I have a couple of things. First of all, an observation that may help focus us. Again, I'm not saying that you can't question Mr. Carretta about these things, but it's possible that they don't matter. And that is the details of the Connecticut or New Jersey operations. Question if you want, but I'm not sure we need to get into that. And also, the fact that his company would both oppose the Connecticut plan and still participate in it, I don't find particularly meaningful in the sense that it's like saying you want to change the rules—I don't think you should change the rules, but if you change the rules I'll play by those rules, and if I can benefit from it I will. I don't find that particularly meaningful. I throw that

out for the cross-examiner to just consider maybe not going into that area.

But I do want to clarify, before the cross, the position of PSEG in regard to the Maryland plan. And let me make sure I understand the contention here. That is, your position that by virtue of what Maryland did, and what happened, that the price that you, I suppose everybody else, can receive for electricity is 27 and a half dollars less per milliwatt hour?

THE WITNESS: Yes, PJM did a what they called a sensitivity study after the auction. And I believe they pulled out 100—or 750 megawatts, which is possibly a little bigger [25] than the CPV plan. Now, PJM, in preparing this study, had accessed its itself to all of the bids that were submitted. So as I understand the sensitivity study, what they were saying is if this 750 megawatts hadn't been there, that a different unit or set of units or maybe demand response, would have been the marginal unit. And that would have resulted in higher price.

THE COURT: I know we're going to hear testimony about this from various people. And I'm very interested. And I just want to get your position is that whether it's 27 and a half dollars, or is it fair to say that because of what happened by virtue of the order, your company and others like you are getting less than you would have without it, whether it's—

THE WITNESS: That is correct. And as I said, it effects or ability to recover previous expenditures that we made and also—it also influences our future investment decisions.

THE COURT: Okay. I mean future investment decisions, like the Seaborn plant, this tilted you

against expanding it because you're going to get less money for it, correct?

THE WITNESS: Yes. And also the concern that these programs would become even more predominant than they are.

THE COURT: All right. I don't want to sound like I'm minimizing it, but I just want to focus it. The essence is [26] that as far as what happened means you, and others similarly situated, will get less. And that's the gripe that you have. And it's based upon your contention that the reason you're getting less is they've interfered with the market.

THE WITNESS: With the competitive market, exactly.

THE COURT: That's fine. I just wanted to get that clear. All right. Fine. With that, cross-examination?

CROSS-EXAMINATION

BY MR. KLEINMAN:

Q Thank you, Your Honor. Good afternoon, Mr. Carretta.

A Good afternoon, Mr. Kleinman.

Q Nice to see you again.

A Nice to see you too.

MR. KLEINMAN: I want to assure the Court that I'm not interested in exploring the potential inconsistency in the position, if you're going to change the rules then I'm going to participate. But I do, Your Honor, want to go through with Mr. Carretta here, as we did in deposition, some of the details about the Connecticut contracting situation. Because I think it

bears importantly on field pre-emption, for reasons think will be clear. However, the first thing I want to do is to talk about the sensitivity study for a moment that Mr. Carretta just referred to.

Q (BY MR. KLEINMAN) Let me direct your attention to the monitor. And I don't have a copy because I didn't anticipate [27] using it. But this is a map of Maryland, is it not?

A Yes.

Q What we tried to depict in the middle here in the red is Southwest MAAC, generally look like Southwest MAAC to you?

A Yes, as a general matter, yeah.

Q And, you know, do you not, that Southwest MAAC does not include the Eastern Shore portion of Maryland?

A That is correct, that's Eastern MAAC.

Q And nor does it include Western Maryland, correct?

A That is correct.

Q Now, can you explain to Judge Garbis, that to the extent that capacity clearing prices were lower than they otherwise would have been, you and other generators will receive, I think you said, $90 million less for PSEG?

A That's—yes, that's our calculation.

Q This map depicts generation in Maryland, both in Southwest MAAC and without Southwest MAAC. And I'm going to ask you to assume that each of the yellow dots is indeed a power plant that participates in the PJM market?

A Okay.

Q It would be your understanding, would it not, that if the Maryland program has caused market clearing prices to go down for generators, generators who are outside of Southwest MAAC, but are inside of Maryland, would suffer proportionally the same effect based on how much they bid and clear, correct?

[28] A Everything that is in MAAC was effected by that outcome, yes.

Q And everything that was in EMAAC was effected by the outcome, was it not?

A Eastern MAAC is part of MAAC, yes.

Q So as a consequence, if the Maryland program had a bad effect on generators, it had a bad effect on generators everywhere, not just in Southwest MAAC. In other words, the effect is not discriminatory against Maryland and non Maryland?

A Well, that's correct. It had an effect on MAAC. And I think, and I could look at the sensitivity study, I think it even had some effect on the RTO, smaller effect, the rest of the RTO.

Q Does PSEG have any RMR contracts?

A No.

Q Have you had any RMR contracts?

A Yes.

Q Can you explain to Judge Garbis what a RMR contract is?

A An RMR contract means Reliability Must Run contract. AnRMR contract is a way of addressing situations where a unit desires to be retired, but the ISO—I'm talking about PJM.

Q Right.

A The unit desires to be retired, but the ISO determines that there's a reliability need to continue operating the unit. [29] So the ISO will, in those circumstances, allow the RMR plant owner to receive an income stream to continue the plant in operation until the reliability upgrades generally are made.

Q And would it be correct to assume that in that income stream that's guaranteed to the unit owner, there is some money for reasonable profit?

A Not necessarily.

Q You think it could be only at cost, with no return on investment?

A The structure of the RMR arrangement under PJM, if I recall correctly, is it's really an unavoidable cost payment. Now there is a provision that allows a company that wants to have an RMR contract, to make a full cost-of-service filing before the FERC.

Q And if a company makes such a filing on cost-of-service basis, then you would expect they would get a reasonable return on their investment, correct?

A There would be some return on investment included in their payment.

Q Does PSEG, the utility, own any transmission, which is part of the PJM transmission grid?

A Yes.

Q And how are you compensated for that?

A We have a formula rate—or they have a formula rate, I should say, and it's also a type of cost—it's a type of [30] cost-of-service payment.

Q And you are guaranteed a return on your investment and those assets too, are you not?

A You're guaranteed the return that's determined to be reasonable by the commission.

Q Do you recall how much FERC returns as a return on investment for transmission assets?

A No, I don't recall.

Q If I suggested to you it was 12 and three-quarters percent, would that shock the conscious or be out of range?

A No, that seems to be in the ballpark.

Q Okay. So now we have RMR contracts that can provide a profit opportunity, and we've got profit on transmission. Now let's talk about PSEG New Haven. Can you explain previously what you understood was the regulatory and legislative back up again, or the process that lead to the contract that PSEG New Haven has?

A As I understand it, there was a law passed in the legislature that I'm not sure if it actually directed the state commission to engage in a procurement or gave them the power to engage in a procurement.

Q But you do recall that the Connecticut Department of Public Utilities engaged in a procurement process, right?

A Absolutely.

Q And that included a needs assessment, did it not?

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

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PPL ENERGYPLUS, LLC,

Plaintiff,

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March 4th, 2013

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H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire

* * * *

[58] or 10 minutes we would be done in, you know, within two hours from there.

THE COURT: Okay. That's what I said in the report, everybody's agreed with that. Why don't we take 15 minutes to brace ourselves for this witness. Thank you.

(A recess was taken.)

MR. MEYER: Plaintiff's call Michael Cudwadie.

THE CLERK: Please stand and raise your right hand.

MICHAEL S. CUDWADIE,

called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, I need you to adjust that microphone to yourself. That's great. Right where you are. If you would state your name and spell your name for the record.

THE WITNESS: My name is Michael S. Cudwadie, C-u-d-w-a-d-i-e.

DIRECT EXAMINATION

BY MR. MEYER:

Q Good afternoon—good evening, Mr. Cudwadie. By whom are you employed?

A PPL EnergyPlus.

Q Can you briefly describe your educational background?

A I have a BS in accounting from Penn State University, an [59] MBA from Lehigh University.

Q And how long have you been employed by PPL?

A It will be 33 years this summer, and 18 of that on the marketing and trading side of the business.

Q What is your current position?

A Vice president, trading east.

Q And what were your prior positions at PPL?

A At PPL I was in internal audit for about six years. Did operation and reviews within the corporation. Spent nine years in the power contract accounting group where I administered long-term capacity and energy sales agreements. I then transferred over to EnergyPlus, served as a trader, served as manager of electricity trading, director of trading and marketing, and now my current position of VP trading east.

Q In your position as VP trading east, what are your responsibilities?

A I'm responsible for all the hedging and trading activities around our eastern assets, as well as the proprietary speculative trading activities. Our assets are located in the PJM markets, so most of our activity is in PJM, but we also have activity in New England, New York, and Mycell.

Q I don't know if the Court is having trouble, you may want to slow down just a little bit.

A Okay.

Q So Mr. Cudwadie, are you familiar with the order of the

* * * *

[94] maybe they do. Then CPV is perhaps subsidizing—go ahead.

MR. MEYER: I would suggest, Your Honor, although I don't want to interrupt this, that one way or the other we know what the dollars per megawatt day that CPV will receive at the end of the day in connection with a transaction. But I will leave behind that point. And it will come out to Your Honor what the contract price is, in fact I think believe in the pretrial brief, so you know what the number is.

THE COURT: All right. That's fine.

Q (BY MR. MEYER) Now, Mr. Cudwadie, we've spent some time on the pricing provisions of the contract. Let me ask you, does the pricing contract, the contract that we're looking at, reflected in Plaintiff's Exhibit 48, have provisions that distinguish it from the kind of purely financial contracts we were talking about earlier?

A Yes, it does. It has—contains provisions to build generation, provisions to operate that generation, and participate in the PJM capacity and energy markets, and it also has provisions that regulate the manner in which CPV will participate in those PJM markets.

Q And let's walk through each of the categories that you've just identified, if we could, using Plaintiff's Exhibit 48. First, could you show us examples of provisions regarding the building and operating of a plant?

A Yes, if you look on page 14, which is up on the screen, [95] Article 2, Section 2.1. "Summary of

Facility Development and Construction. The supplier shall construct, own, operate, and maintain the facility, which shall consist of a natural gas combined-cycle generation facility, located in Charles County, Maryland, having an original contract quantity of 661 megawatts."

The location of that is found on page 15, section 2.2, "Location. The facility shall be physically located entirely within the Southwest MAAC location deliverability area."

Flipping the page to page 16, Section 2.5, there are milestones for commercial operation. These milestones must be reached in a timely manner.

Moving ahead, page 18, Section 2.6, there are also requirements for commercial operation, such as completing its interconnection agreement with PJM. And these are provisions that I was speaking of relating to the order for generation to be built.

Q I believe you mentioned as your second category of provisions, provisions that require CPV to participate in PJM markets?

A That is correct.

Q Could you identify for us the provisions you are referring to there?

A Sure. Looking at page 19, Section 2.6 (d), "The supplier [96] shall participate in the BRA, the Day-Ahead Energy Market, Real-time Energy Market, Ancillary Services Market, or other markets as determined by the Maryland PSC in accordance with Section 3.2."

So let's take a look at Section 3.2. That is on page 26. Section A, 3.2(a), "The supplier represents, warrants, and covenants that the facility is eligible to

and will offer into all PJM markets pursuant to PJM agreements and, to the extent consistent therewith, guidelines established by the Maryland PSC, including but not limited to the BRA, the Day-Ahead Energy Market, Real-time Energy Market, and the Ancillary Services Market."

3.2(b), "Beginning on the BRA auction date, covering capacity obligations for the delivery year that first follows the commercial operation date, the supplier will have the units offer in the BRA." That is the planning year 15/16 auction that happened in May of last year that we were discussing earlier.

Section 3.2(b)(2), "Beginning on a commercial operation date, supplier will have the units offered in the Day-Ahead Energy Market, Real-time Energy Market, and Ancillary Services Market."

Q Now, you've mentioned as well, provisions relating to the manner in which CPV is required to participate in those markets?

[97] A Yes. We'll have to flip back to page 19, Section 2.6(d), again, "It's the supplier shall participate in the BRA Auction, the Day-Ahead Energy Market, Real-time Energy Market, Ancillary Services Market, or other markets as determined by the Maryland PSC." That is the manner of participation.

Next flip back to Section 3.2 where we were earlier. And I won't make you type the whole paragraph out again, but if you look in Section 3.2(a), right in the middle of that paragraph it says, "Guidelines established by the Maryland PSC."

Last sentence in 3.2(b), "The suplier will continue to have units offered in the BRA until otherwise directed by the Maryland PSC."

Moving down to 3.2(b)2, middle of the paragraph, "The units will submit cost-based offers."

Moving to Section 3.2(d) on page 27, middle of that paragraph, "Except for the sale of products and services to PJM provided for herein, this agreement precludes this supplier from entering into a bilateral contract or other arrangement to sell any of its output products or services, including but not limited to reliability, must-run agreements, or any similar arrangement with another third party, PJM, or any government agency, during the term of this agreement unless approved by the Maryland PSC."

And there's one more. And that is on page 34, top of [98] the page, Section 6.2, "Determination of Monthly Payment Amount. Section (a), "No monthly payment amount shall be provided during any period in which the supplier has not been selected to provide capacity in PJM's BRA auction." Meaning, to get paid they have to clear the auction. That same type of principle applies to the energy market as well. If they're going to get payment under the contract, they must clear megawatts in the energy market.

Q Thank you, Mr. Cudwadie. Now, the kinds of provisions you've just described, just so we're clear, those provisions distinguish this contract from a purely financial contract as you described it before?

A Absolutely would be quite different than a pure financial contract.

Q Let me direction your attention to Plaintiff's Exhibit 456. Now, you were asked at your deposition

in this case in January, about a contract between PPL and the counter-party. I'm sorry, we had a snafu, I don't seem to have Plaintiff's 456. Can I borrow someone else's copy?

MR. KLEINMAN: Here you go.

MR. MEYER: Thank you.

Q (BY MR. MEYER) Is this a copy of the contract you were shown at your deposition?

A Yes, it is.

Q And this contract is described on the cover as Electric [99] Energy and Capacity Contract for Differences by and Between the counter-party and PPL EnergyPlus, LLC, do you see that?

A Yes, I do. That is correct.

Q Now, is this contract one that is purely financial, in the sense you've been describing during the course of your testimony this evening?

A Yes, it is.

Q Now, Mr. Cudwadie, let me ask you, where in this contract would you find provisions in the categories you described a moment ago that characterize the CPV contract, pricing contract for differences?

A None of those provisions are present in this Longview PPL EnergyPlus agreement. In fact, if you would turn to Article 5 on page 13, it describes the financial transaction. Section 5.1, "Financial Settlements; No Physical Deliveries. The transactions contemplated by this agreement shall be settled financially at PJM West Hub (in the case of Energy Differences) and at the capacity pricing zone (in the case of Capacity Difference Payments.) Longview shall

have no obligation to provide or arrange for physical deliveries. And PPL shall have no obligation to accept physical deliveries or arrange for physical acceptance of electric energy or capacity, whether from the facility or otherwise."

So absolutely no physical transactions apply. No provision to bill the generator. No provision to settle any of [100] the output from this unit into the energy markets. And also I will point out that Section 5.3 on page 14, "No Exclusivity. Nothing in this agreement shall be construed to limit the right of either party to, one, purchase or sell any capacity, electric energy, ancillary service, or other product, services, rights, or things of value, whether generated or produced at the facility or otherwise." Meaning Longview can do whatever it chooses with the output from its plant. They are not obligated to deliver in any way to PPL.

If you recall from the CPV contract, Section 3.2(d), Longview cannot—or sorry, CPV cannot enter into any bilateral contracts to sell the output from their plant to anybody other than PJM, unless approved by the Maryland PSC.

Q Referring to Section 5.3, is that -- I may have missed your reference?

A I said 3.2(d), I would like to check that.

Q Let me direct your attention to page 14, Section 5.3?

A I was referencing the CPV contract, section 3.2(d) that indicated they are not allowed to do any type of bilateral transactions in the market, or enter RMR agreements, or anything like that without the approval of the PSC.

Q I misunderstood. So the CPV pricing contract, that provision prohibits bilateral contracts. The provision in the contract we're looking at here, Plaintiff's 456, Section 5.3, is the provision you referred to as not imposing that [101] limitation?

A Correct, in Longview contract there are no restrictions. In the CPV contract there are.

Q Okay. So direct your attention, though, Mr. Cudwadie, to the Recital to the contract, the Longview contract. The first "whereas" clause on page 1 of the contract. Be there in a minute.

MR. MEYER: Your Honor, do you have a copy accessible to you? We can just go off the printed copy.

THE COURT: Yes.

Q (BY MR. MEYER) And, Mr. Cudwadie, you have the contract in front of you, the Plaintiff's Exhibit 456?

A I do.

Q Okay. So I'm referring you to the Recital on page—the first—the page before the numbered page 2, I believe is page 1 of the contract, doesn't have a number on the bottom. Do you see that first Recital? "Longview intends to construct, own, and operate an approximately 695 megawatt coal-fired electric generation facility to be located near Maidsville, West Virginia," do you see that?

A I'm catching up with you. What page is that? I was in the wrong agreement.

UNIDENTIFIED SPEAKER: The front page.

A Okay. Read that again and I hopefully will find it.

Q (BY MR. MEYER) The first whereas clause, beginning [102] "Longview intends to construct," it's also showing on your screen now?

A Okay. I'll look there. Okay.

Q So doesn't that Recital refer to an intention that Longview had to construct, own, and operate this generation facility?

A It has nothing to do with the financial contract between PPL and Longview.

Q Well, if Longview did build a plant, would Longview make sales of capacity to PJM?

A They could.

Q Would they have to?

A No.

Q What would happen if Longview didn't build a plant?

A They certainly wouldn't be making any physical sales of capacity and energy to anybody. They would still have the obligation of this financial contract for differences that they signed with PPL. They'd still have to honor and settle that contract in some way, either by settling it in the ongoing process over the five-year term, or by financially settling it in advance.

Q So even if Longview sold no units of energy or capacity from the Maidsville, West Virginia facility, referred to in this Recital, this agreement would still involve a financial settlement between a contract price and some reference price?

[103] A Correct. Because whether Longview builds a plant or not, those reference prices will be out there to settle this contract against.

Q Okay. Well, Mr. Cudwadie, I want to wrap up this line of questioning. I direct your attention back to Plaintiff's Exhibit 2. This was the December 2011 RFP. And I'd like to direct your attention to page 5 of the RFP. Not the contract, the RFP. There is a reference there in numbered paragraph 3 to contract structure. And you see in that paragraph, towards the bottom, there's a sentence that says, "The financial arrangement between the buyer and seller for capacity and energy will be a contract for differences, hence—continues—the delivery of capacity and energy will be settled financially rather than physically, thereby providing compensation to supplier for capacity and energy." That's referring to financial settlement of the sort we just talked about in connection with the Longview contract. Does the fact that there's a financial settlement have something to do with whether the contract is regarded as purely financial?

A No. I mean, the fact that there is a financial settlement at the end of some period, I mean, it's perfectly normal, all contracts are settled out for some type of monetary consideration at some point in time. The substance of this agreement has to do with building generation, and selling the physical output from that generation into the PJM capacity and [104] energy markets.

And I think the contract structure actually captures that. I'm going to read a sentence from the -- about three-quarters of the way through from the contract structure paragraph. And it says, "Hence, the delivery of capacity and energy—"To deliver capacity and energy you have to be selling a physical product. They are delivering capacity. They are delivering energy into the PJM market. "—Will be settled, thereby"—I left out the financial rather than physical, because

we've already established that really doesn't have any substance here or isn't relevant—"thereby providing compensation to supplier CPV for capacity energy."

So it is saying in here, this is what you will be compensated for. You will produce and sell capacity and energy. You will sell it into the PJM market. And the pricing contract will pay you for those physical deliveries.

Absolutely nothing to do with a financial contract.

Q Okay. Well, thank you. I'd like to transition to a discussion, or to the topic of PPL's own participation in PJM's capacity and energy markets. Let's start with capacity. Are you familiar with PJM's position in—excuse me, PPL's participation in PJM's capacity markets?

A I'm familiar with the PJM capacity markets and the RPM auction.

Q And what is the RPM auction?

[105] A The RPM auction is the FERC approved way to achieve resource adequacy in PJM, and to determine the price for those reliability products that provide that reliability.

Q And RPM stands for what?

A Reliability Pricing Model, RPM.

Q How does RPM accomplish the objective you just described?

A It provides a revenue stream to the generator to supplement the revenues earned in the Energy and Ancillary Services Markets. Since PJM does not have scarcity pricing, generators don't earn enough revenue in the Energy and Ancillary Services Market to support the reliability levels that PJM needs. There's

a gap. The capacity payment fills in that gap. And through the auction process it's also an excellent way to send out a market signal to reliability resources where they might want to locate.

Q And how does RPM provide the kind of market signal you just described?

A We talked a little bit about this earlier, it's through the—it's an auction process. The primary auction is the Base Residual Auction, BRA. That is held three years in advance of the delivery year. Delivery years start on June 1st of one year and end on May 31st the following year. The three-year period allows time for resources to digest the market prices they're seeing from the auction, and plan entry [106] into the market.

There are also incremental auctions. Let me back up. For point of reference, the planning year 16/17 auction will be held this May, May of '13, three years in advance of the delivery period. In between that auction, in May of '13, and delivery starting 6/1/16, there will be three incremental auctions. The first will be September of 2014, followed by one in July of 15, followed by another in February of 16.

The purpose of these incremental auctions is for efficiency. To catch up with changes in load, changes in transmission, changes in generator plans that may have happened between the May '13 auction and delivery. It also gives an opportunity for resources that weren't cleared at a BRA auction. Some resources are offered in the auction, but don't clear. This gives them a second opportunity to participate in the auction and be cleared as a capacity resource.

It is run for the RTL. At times you'll have local delivery, deliverability areas, LDAs, which will have a

separate price from the RTL. This is a function of cheaper resources from the area surrounding the LDA being limited to be used as a capacity resource within the LDA. That is generally what causes price separation, and sends a price signal to the market that LDA is a place to locate a resource, a reliability resource.

Q I want to come back and talk about locational [107] deliverability areas in a moment. Before we get there, let me ask you this about PPL's own bidding of capacity resources into the base residual auction. How does PPL decide what to bid when it offers its own resources into the capacity auction?

A Well, some of our resources are mitigated, they're capped. We don't have a lot of discretion with those. Others where we've uprated the units, added additional capability to the unit, increase the output, they're subject to the Minimum Offered Price Rule, the MOPR. So there is a floor on those offers.

We also have some units that we're able to offer in that we have a bit more discretion on. For those units we'll look to market signals, things that are going to effect the auction clearing price, such as changes in load, retirements of units, new generation coming on, changes in pollution control legislation, and even the entry of subsidized units. All things that will have an impact on the market price, we'll look at that to determine where we want to set our bid.

We'll also look at the value of capacity in neighboring markets. If New York is valued at $150, and our unit can deliver to New York, we might want to offer it into PJM at $150, saying our fall back is New York. If PJM clears higher, we'll sell it to PJM. If PJM

clears lower than New York, then we'll move our capacity out.

We look at also an insurance value. We talked a [108] little earlier about when units don't perform there are capacity penalties, and you're penalized at a rate that takes back your annual RPM payment at a quicker rate. Sometimes it makes sense to hold some of your units in reserve for failures that may happen during the planning delivery. So that would be another factor that we consider.

And, finally, if we were making any type of improvements to our units, uprates, we'd look at the capital investment of those uprates and say this is the revenue stream we would need to support those investments. Offer in at that level to support the project. And if we determine the project's maybe a sunk cost, we may just enter the market as a price taker.

Q You mentioned that for some—for new units you might have a floor on the bid that you're able to offer into the auction market; is that right?

A That is correct.

Q And with respect to a new unit, would PPL necessary—would PPL necessarily offer in at the lowest price that was allowed by PJM rules?

A That would be irrational. We would determine what revenue we had to get out of the capacity market, and offer the unit in at that level to support the project. If it isn't built yet, and it's going to cost, pick a number, $200 a megawatt day, doesn't make sense to offer it in at anything less than $200. [109] We'd offer it at $200. That's what the project needs to be a go. If it clears at $200 and higher, then we'll obviously clear

in that auction. Still doesn't mean that we would necessarily build that unit, because you'd have to look at the stream of revenues over the life of the unit. But it has cleared at least one auction. It would give us incentive to, in the next auction, offer in at a very similar price. Clears two auctions in a row, that project's a go.

Q Staying with that example that you just described, if PPL had a guaranteed level of capacity revenues under a long-term contract, would that effect its bidding strategy in the auction?

A Absolutely. If I had a guaranteed payment, and I would get that payment by clearing the auction, my incentive is just that, to clear the auction. I would offer it in as low as possible, because I don't—my bid doesn't have to be rational anymore to support the project. I really don't care what the auction clears- at, because my price will be determined by the pricing contract. And I have a guaranteed price that supports that project.

Q But this MOPR rule that you've referred to, wouldn't that control how low you could actually bid?

A Sure. But it wouldn't change the incentive. If I had that contract that you're speaking of, I would probably be down at PJM right now saying, you know what, I think I can get this [110] project in. I can cut a few corners here, there, better financing, anything to get that floor lowered. Because again I'm not really concerned about what my bid is. I'm not concerned what the auction clears at. My project is supported by the guaranteed payment outside of the PJM market.

Q So let's come back to the subject that you alluded to a few moments ago, shifting gears. You mentioned Locational Deliverability Areas, could you

explain for the Court how the RPM auction process sends location specific price signals?

A It's one of the key elements of the RPM auction. And it might be best if we can put up a map of PJM so I can kind of point to things.

Q Let's use Plaintiff's Demonstrative 44 then. Looks like the coloring on the two aren't exactly the same.

A Okay. What we see here is PJM RTO, entire area here. We're actually missing a little bit of ConEd territory in northern Illinois and a little bit of FE territory in northern Indiana and Michigan, they kind of got cut off this particular map. But it doesn't change the essence of what I want to talk about.

And is that is you have the RTO. Within the RTO there are eight LDAs. MAAC happens to be one of those LDAs. MAAC includes parts of Pennsylvania, all of New Jersey, little bit of Virginia down here on the peninsula, portions of Maryland, and back into Pennsylvania again. MAAC is an LDA of [111] the RTO. Within MAAC there are two LDAs, Eastern MAAC and Southwest MAAC.

Now, to send the price signal that we were talking about, the first thing that has to happen is you have to be modeled as an LDA to get that price separation. There are rules for this. Certain regions are always modeled. MAAC is always modeled, EMAAC is modeled, and so is Southwest MAAC. You would also be modeled as an LDA if you had cleared three previous auctions at a price separate or different from the RTO.

There's also a third requirement that if your CETL to CETO ratio is less than 115 percent, and CETL is

Capacity Emergency Transmission Limit, it's wires in the air, import capability, if you would. The denominator CETO, Capacity Emergency Transmission Objective. That's the minimum amount of import capability you need to meet PJM's requirement of one day in 25 loss load. So as that ratio gets smaller, the wires you need are getting closer to the wires that are hanging there. So if it clears—if it winds up at a ratio of less than 115, that will be modeled as an LDA as well.

Now, the fact that you're modeled as an LDA doesn't mean you will clear separately. What will determine the clearing price, and whether there's separation or not, is when the ability to transfer cheaper units, and looking at RTO into MAAC, when ability to transfer cheaper resources from the RTO [112] into MAAC is limited by that CETL, the import capability, at that point in time no further resources can come in from the RTO. If the reliability requirement is not met within the subregion MAAC, a resource from within that MAAC area would meet that requirement at a higher price, and that LDA will separate, sending the price signal to the market that MAAC has a higher price than the rest of RTO.

Q Perhaps it would be helpful to get a little bit concrete. Let me direct your attention to Plaintiff's Exhibit 63, which is the, I believe, the actual results as reported by PJM from the most recent Base Residual Auction.

A That is correct.

Q And directing your attention to page 14 on this document, there is a table that is described in the document as auction clearing results in the LDAs, do you see that?

A Yes, I do.

Q Could you perhaps use that table to illustrate the concept of pricing separation as you've described it?

A Yes, if you look at the last line under RTO, you'll see $136 price. That is the resource clearing price for the RTO. You can see that MAAC cleared at $167.46, indicating there was separation between MAAC and RTO. These results also tell you that all of the subregions of MAAC, which are Southwest MAAC, Pepco, EMAAC, DPL South, PSEG and PS-North, all cleared at $167. So there was no separation within the MAAC region. Also [113] it tells you that the highest clearing price, highest separation existed in the ATSI zone, which is the northern Ohio area.

Q Let me direct your attention to Plaintiff's Demonstrative No. 45. And that was—is this—what is this depicting, Mr. Cudwadie.

A It's depicting the clearing prices in the 15/16 BRA auction. You see MAAC clearing in the light blue color, all one price, $167.46, for the entire MAAC, which includes Southwest MAAC and Eastern MAAC. ATSI is clearing at $357 in the yellow area. And the darker blue is the rest of RTO, it is clearing at $136. So that represents exactly what was in table No. 4 in the PJM Residual Base Auction results.

Q So now just to make sure we've got the nomenclature here. The RTO as you described, again, it's the entire region, correct.

A Correct, RTO, entire region.

Q Okay. So the $136 price is the price for capacity applicable to the portion of the entire region, other

than these LDAs that cleared at a higher price; is that correct?

A That is correct. It would be the price for all the darker blue area.

Q Now, so help us understand, what does it mean—what do we know, based on the fact that MAAC cleared at a higher price, a separate price from the RTO?

[114] A Well, obviously we know there was price separation there, but maybe the more important thing is how we did get price separation between MAAC and RTO. And I will point out that the capacity auction is an economic auction. Meaning the lowest priced resources, lowest priced offers will be taken first. As long as there is import capability between RTO into MAAC. That way if the resource is in RTO, and it's the cheapest resource, that moves into MAAC and becomes part of MAAC's supply curve.

The fact that we saw price separation between MAAC and RTO indicates that the limit between RTO and MAAC for CETL was reached. And that the reliability requirement, the amount of megawatts needed to clear the auction, was not met at the point that the last import came in. Meaning that something within the MAAC region had to set the price. And it was a higher price than what the rest of RTO was.

Q So there is a separate supply curve for MAAC that's modeled against a separate demand curve for MAAC?

A That is correct. Every LDA that is modeled separately, that's exactly what modeled separately means. It's separate demand curve and a separate supply curve for that region.

Q So it's a supply curve for MAAC. Does the fact that MAAC separated from the RTO mean that the only resources in the supply curve for MAAC are resources in MAAC?

A Absolutely not. It—what actually happened was the cheaper resources that are out here in this RTO that were [115] setting the $136 price, were actually part of the supply curve for MAAC up to the import limit RTO into MAAC.

Q Okay. And does the fact that MAAC separated from the RTO, in terms of price, indicate that there was a shortage of capacity in MAAC?

A No it does not. If I can direct you back to page 14, Table 4 of the PJM results, Tab P063, top line under the MAAC column says, "Offered megawatts," 74,260.5. Cleared megawatts, 65,790.4. Tells me that there's just under 8,500 megawatts of uncleared capacity in MAAC. So there's no capacity shortage in MAAC. The price that -- the fact that the price separated between MAAC and RTO means that the CETL limit was reached. And the resource that set the clearing price, that extended the supply curve to cross the demand curve was at a higher price than the RTO assets, the next cheapest asset in RTO.

Q So let's look at Southwest MAAC and MAAC now. Southwest MAAC, as you've said, is a subregion of MAAC, it's an LDA within the MAAC LDA?

A That is correct.

Q What are the boundaries of Southwest MAAC?

A The boundaries of Southwest MAAC are the historical service territories for Baltimore Gas and Electric and Pepco. Looking at the map, the northern boundary is the Maryland boundary with

Pennsylvania, southern boundary is the Maryland border, eastern boundary is the Chesapeake, and the western [116] boundary follows the Potomac River to a certain point, then goes directly north, kind of cutting off the panhandle of Maryland if you would.

Q Do those boundaries of Southwest MAAC line up with transmission constraints?

A Today's transmission constraints? I would be surprised if they do. I mean, you've got to remember when they were—when each individual area was operating their service territory, BGE was operating theirs, Pepco theirs, PPL theirs, they balance to their own control area. What I mean by that is generation and load were balancing. Load went up, generation was raised within that control area to meet that obligation.

There were interchange points between the control areas. And they were the weak spot on the system. Now, with all the transmission improvements that PJM has done over the last 15 years, these points have moved. When you correct the weakest link in a transmission system, all that does is push the constraint out to a different weak, your bottleneck has moved.

Also effecting where these bottlenecks will occur is transmission—sorry, generation. We've had a lot of generation retire. We've had a lot of new generation come in. The physical locations of those generators can effect where the bottlenecks occur, as well as what type of fuel they're burning and the cost of that fuel. If the fuel is very cheap, we've [117] seen over the last 18 months in PJM, gas became very cheap. It started displacing coal. It changed the way the power flowed on the system. Bottlenecks showed up in different

areas. So the point is I don't think it would be highly likely that the bottlenecks for transmission would be occurring at the boundaries of the old service territories.

Q Let's turn back to the auction results that we saw in Plaintiff's Exhibit 63. What do these results show—say about Southwest MAAC and MAAC?

Well, they tell you that both Southwest MAAC and MAAC cleared at $167.46, as did all the other subregions of MAAC. So it's telling me that MAAC cleared at one price. If you look at page 15 of the PJM, 15/16 RPM Base Residual Auction results, it actually depicts the clearing prices since RPM was started back in 2007/08. And you can see that Southwest MAAC is the green line. MAAC is the purple line. And for that 07/08 auction MAAC cleared at $40.80, Southwest MAAC was $188.54. You can see that there were separations in the early auctions. But by 2010 and 2011 Southwest MAAC and MAAC have been clearing as one zone. And you can see the $167.46 out at on the extreme right-hand side. So basically what I'm saying is Southwest MAAC and MAAC cleared as one, and it's been like that for the last six BRA auctions.

Q So if I'm reading this chart correctly, the green line depicting Southwest MAAC, merges with the MAAC line, and [118] essentially disappears and follows the MAAC line, is that an accurate—

A That's—exactly. They merge at the 2010/11 year.

Q Okay. And what does it mean for these periods, these auctions in which MAAC and Southwest MAAC did not separate, what does that mean?

A That means that the—both MAAC, Southwest MAAC, and all the other LDAs within MAAC, share the same pool of resources. Capacity is completely fungible within MAAC, meaning that a capacity resource in Pennsylvania can meet the need -- a capacity obligation of load in Maryland and vice versa, a Maryland generator can supply the capacity need for a load in Pennsylvania.

Q And is there any significance to the fact, as shown on this chart, that MAAC and Southwest MAAC did separate prior to the auction for 2010/11. So let me first ask—so that the numbers on the bottom of this chart are the years?

A The planning years, yes.

Q The delivery years?

A Yes, the delivery years.

Q Okay. So the auction for 2010/2011 is what I was referring to, when was that held?

A The 2010/2011 is the first year that they cleared as one. I don't know the exact date for that particular auction, but it had to be probably getting close to maybe two years, eight [119] months in front of the auction.

Q Okay. So let me ask. Now, is there significance to the fact that Southwest MAAC and MAAC separated in the RPM auctions run prior to the auction for the planning year 2010/2011?

A Yes, there's an explanation for that. And it has to do with RPM starting for planning year 07/08. The BRA auction for 07/08 was held in April of 2007, literally days in front of the delivery period. In fact, the first five auctions up through 2011/12 were held

from that first one in April of '07, the last one was held in May of 2008.

So over a 13-month span, five auctions occurred. This is significant because it cut down on the timing, or the preparation period, that reliability resources had to enter the market. The first one there was only a matter of days for 07/08, so nothing could have been planned to enter in that short of a time period. And the fact there wasn't enough time for entry of new resources, we wound up with a very, very steep supply curve.

And the impact of this is that even minor changes in a load forecast, or minor changes in a forced outage factor for units in an area, could effect where the price cleared. Because only a small movement in the demand curve can create a large price separation in the auction.

As time pushed out, and we were providing the reliability resources with a little more time to digest the [120] prices and to get near three years, or even the full three years to plan entry, we saw the supply curve flatten out, and you saw less volatility in the prices. Prices were a bit more rational. And they started clearing together even prior to the full three-year period as you pointed out in 10/11. So it was just simply a matter of time and the fact that RPM was implemented over—it had a transition period.

Q Okay. And in focusing now on Southwest MAAC and potential separation between Southwest MAAC and MAAC. If there were separation between Southwest MAAC and MAAC, what would that mean for resources in the Southwest MAAC portion of MAAC, and the MAAC portion of MAAC, as relates to capacity prices within Southwest MAAC?

A If there was separation between MAAC and Southwest MAAC, what it would mean is that the import capability for Southwest MAAC is 8,373 megawatts. That means for that first 8,300 megawatts, that resources within MAAC, if they were cheaper, would be placed on the supply curve for Southwest MAAC, at the base. PJM builds a supply curve.

It's kind of like building blocks when you were a kid. Look at what the cheapest offer is out there, is it in MAAC or Southwest MAAC? If it happens to be zero, and it's in Southwest—or it's in MAAC, there's enough import capability available, that becomes the first building block. If the next cheapest offer was $5, again it's in MAAC, you compare to what [121] import capability you have. If you ask still import, that block goes. The next block happens to be a Southwest MAAC asset. No restrictions on that, it's already in Southwest MAAC. That becomes the third block. This continues, this process, up until you hit the transfer limit, the 8,373. That means you cannot bring any resources in from MAAC into Southwest MAAC.

Now what has happened up to that point, all the cheap resources that were able to come in to MAAC from Southwest MAAC did, and are actually going have an impact on where the price clears in MAAC.

Q Did you mean to say resources from MAAC into Southwest MAAC?

A The resources are always coming from MAAC into Southwest MAAC. They're coming from the region around into the LDA. Okay. So if I'm getting it backwards, I'm always talking about MAAC into Southwest MAAC. Point is that the cheaper MAAC resources, even though they're limited by The import

capability, will still participate in lowering the overall price in Southwest MAAC, because it is moving the supply curve. It's shifting it out to the right, lowering it. You'll ultimately have a lower intersection point with the demand curve.

Now you still haven't gotten price separation just because you hit the transfer limit. What will determine if [122] there actually is price separation, if you need one more megawatt in Southwest MAAC to meet the reliability requirement, and that next cheapest megawatt's in Southwest MAAC, you will use that next cheapest megawatt of Southwest MAAC and you don't have separation. But if the next cheapest megawatt was in MAAC, you can't get it in because the transfer capability is used up, then you will get price separation. Because that last megawatt will have to come from Southwest MAAC.

And by definition it's higher price. It's going to set the price for Southwest MAAC. It will clear at a price higher than MAAC. Sending a signal to the market saying, if you're looking at locating to a particular area, not that price is necessarily high enough to build generation, but it will just say on a relative basis, Southwest MAAC has a higher price than MAAC.

All the generation within Southwest MAAC will get paid that clearing price. Load in Southwest MAAC will pay something slightly less than that clearing price, because they are—they get the benefit of capacity transfer rights, which are defined, they're explained on the bottom of page 14 in the 15/16 results. But simply stated is the LSC gets a credit for use of the transmission line to bring in these cheaper resources.

They get a credit. They will pay something a little less than the clearing price.

Q I see. So if there's a low cost resource that's located

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 5, 2013

DAY TWO TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire
Kristin Lawrence, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

Reported By:

Jacqueline Sovich, RPR,
CMR, FOCRR

Official Court Reporter

* * * *

[2] (PROCEEDINGS)

THE COURT: Okay. We have, has he escaped?

MR. MEYER: Ready to go.

THE COURT: Did he escape, the witness?

MR. MEYER: No. Plaintiffs call Doug Nazarian, or Judge Nazarian, I should say.

THE COURT: What about the cross-examination?

MR. MEYER: Oh, I'm sorry, Your Honor. We had an understanding that among counsel that we would begin the day with the witness Nazarian and then come back at the end of that and complete the cross.

THE COURT: All right. That's fine.

MR. MEYER: To accommodate the Judge's schedule, Your Honor.

THE WITNESS: Good morning, Your Honor.

THE COURT: Good morning.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would adjust that microphone to with yourself. State your name and then spell your name for the record.

THE WITNESS: Douglas Nazarian, last name N A Z A R I A N.

THE CLERK: Thank you. Counsel?

DIRECT EXAMINATION

[3] BY MR. MEYER:

Q. Shall I call you Judge?

A. You can call me whatever you like.

Q. Well, respectfully, Judge, would you state your current employer?

A. My current employer is the State of Maryland, but I am employed as a Judge on the Court of Special Appeals of Maryland.

Q. And until recently, you were the Chairman of the Public Service Commission of Maryland; is that right?

A. I was.

Q. When did you step down as Chairman?

A. I resigned at the close of business on January 7 of this year.

Q. And when did you join the Public Service Commission of Maryland?

A. I came first to the Public Service Commission on June 27 of 2007 to be the Commission's general counsel. I was in that role until August 16 of 2008, when I was appointed Chairman.

Q. And you were appointed Chairman of the Public Service Commission by Governor O'Malley; is that right?

A. I was.

Q. And Governor O'Malley also appointed you to your current position?

A. He did.

* * * *

[7]terms of the contract.

Do you see that?

A. Yes.

Q. And then if you look to the next attachment, attachment 8, A. Okay.

Q. Attachment 8 is the contract itself, correct?

A. It's a draft contract, yes.

Q. Right. And in issuing the – requiring the EDCs to issue this RFP, the Public Service Commission was requiring them to solicit proposals for this form contract that the PSC had specified, correct?

A. Generally, that's true, yes. I mean we knew, I'll go back and look and see if the order says, so but it's anticipated that there would be some changes to the final terms of the contract, but, yes, that's the form of the contract that was intended.

Q. Okay. Just to step back and develop an overview of the process that ensued following the issuance of the RFP, the EDCs issued these RFPs?

A. Yes.

Q. In late 2011?

A. Yes.

Q. A response was required by sometime in January of 2012?

A. Sounds right.

Q. Proposals came in, proposals were reviewed by a consultant [8] hired by the Public Service Commission, Boston Pacific, correct?

A. Correct.

Q. Boston Pacific evaluated those proposals based on criteria that the Public Service Commission established?

A. Yes, and that were set forth in the RFP

Q. And one of the criterion Boston Pacific evaluated the proposals was benefits to the State of Maryland, correct?

A. That was number 9 of a long list, but yes.

Q. And that Boston Pacific made a recommendation to the Public Service Commission in April of 2012, correct?

A. Might have been March, but same timeframe.

Q. And the recommendation that Boston Pacific made was among the proposals that had come in, Boston Pacific recommended that the Public Service Commission order that the EDCs enter a contract with CPV Maryland?

A. Correct.

Q. And that was the recommendation relating to CPV Maryland's proposal for a facility to start operation in the delivery year 2015?

A. Yes.

Q. Boston Pacific also made a recommendation that although the RFP had potentially envisioned soliciting proposals for more than a thousand MWs of new generation, that the Public Service Commission issue only a single contract for CPV's 661 MW [9] facility, correct?

A. The RFP asked for bids up to 1500, and the recommendation based on our hearing in January and analysis of the reliability concerns on the record that we developed there, based on all that, their recommendation was to order the 661 MW plant and to select the CPV plant, yes, beginning planning year 2015.

Q. Now, the EDCs, PEPCO, BGE, and Delmarva, that the PSC ordered to enter into these contracts, with CPV, those EDCs do not want to enter these contracts, do they?

A. They have expressed in the course of the hearing the view that they would prefer not to do this, yes. Deep in their souls, I don't know what they intend, but they've taken the position in the case they prefer that we didn't go forward.

Q. And the CPV plant, the project that was bid into the RFP process by CPV, is that one that the Public Service Commission anticipated would enter the market absent the orders that the Public Service Commission issued?

A. Oh, sure. We anticipated that it might. That plant was fully certificated in November 2008. CPV was free to build that plant any time it wanted after November of 2008, and then it came in sometime after probably around 2010 to ask for the air permit element of their certificate to be extended, which I believe we did.

So there was certainly a possibility for a number of years that that plant could get built on its own. Now, at the [10] same time, they had been complaining to the legislature, complaining publicly and come to us asking for us to order some sort of contract because they said they couldn't get financing for their project.

And at different times, they'd been more visible and aggressive about that than others. But that plant has been a possibility for a number of years. And it could have been built at any time since November of 2008.

Q. Did the PSC reach any conclusion as to whether CPV would in fact go forward with this project absent the orders of the Public Service Commission?

MR. ERWIN: Objection, Your Honor, deliberative privilege. The conclusions of the PSC are in the April order, which is plaintiffs' 44.

THE COURT: What's the relevance about the Public Service Commission thinking whether CPV would do the deal without this arrangement? The purpose of the arrangement is to induce them or somebody else to do it, Mr. Meyer. I presume that there's no debate that if you asked the reason why you made the proposal is that the hope that somebody would enter into it. I'm not sure where we're going here.

MR. MEYER: Well, I believe, Your Honor, that at the deposition of Judge Nazarian, I did ask questions along the lines you suggest, and it was—the witness was similarly instructed not to answer the question. But I'm perfectly happy [11] to try it that way.

THE COURT: Well, I'm not understanding. Well, why don't you ask your question, because I'm really

not understanding the position with regard to the objection or what is the fuss, since—

BY MR. MEYER:

Q. Judge Nazarian, what is—was the purpose of the order to induce CPV to proceed with the construction of its plant?

A. At the time the case was open, no. It was not targeted to any particular project. The purpose of the case and the ultimate purpose of the order was to address a long run reliability concern that we identified.

Q. To address it by inducing CPV to build its plant?

A. To induce it—to induce a response by directing our utilities to issue RFPs under state law to which CPV and others responded and that ultimately resulted in a decision.

THE COURT: Let's try to be clear here. I don't get the plaintiffs are suggesting that the Public Service Commission had some particular desire to favor CPV.

MR. MEYER: No, Your Honor. That's not the thrust of this at all.

THE COURT: So the question perhaps to avoid a whole fuss is that the RFP is issued with the hope that the incentive there that would attract somebody of the nature of CPV to accept the arrangement.

[12] Isn't that essentially right?

THE WITNESS: That's exactly right, Your Honor.

THE COURT: I mean can't we just move from here?

BY MR. MEYER:

Q. We're moving from here, Your Honor.

Judge Nazarian, in fact, it was the Public Service Commission's view that the market wasn't providing sufficient revenue certainty needed for participants such as CPV and other investors or developers of new generation to build plants in Maryland; is that right?

A. Our position in a lot of forum has been that the market structures within PJM will never provide the signals or the financial support to build power plants in Maryland or in any restructured state because of the way that the market is structured.

Q. So your view is that PJM wholesale markets don't work in restructured states?

A. Our view is that—at least when I was the Chairman, our view was that the structure of the capacity market would never provide any sort of financial support or incentive for long-term assets like power plants. It was great for short-term assets like demand response and energy efficiency. It had its benefits and its advantages, but that it would never anchor long-term assets like power plants. And I still believe that.

[13] Q. Okay. And the way in which the April order of the Public Service Commission addresses that problem is by requiring the EDCs to enter into these contracts guaranteeing the new generator, whoever it would have been, a fixed level of revenues from its new plant over the long run?

A. Among its other provisions, yes, that's true. It's a more complicated transaction than that, but yes, that was the feature of it.

Q. Well, more complicated perhaps, but the thrust of it is this pricing contract for differences, is it says

the Public Service Commission will order the EDCs to set a price, correct?

A. Yes.

Q. The EDCs will set a price providing for the new generators to sell their electricity into the market, if it ends up being worthless than the price that's in the contract, the EDCs will pay the difference. If it's worth more, the generator will pay it back.

So the contract gives the developer the ability to say to its lenders we know we're going to have this level of revenue over the 20 year life of the contract because the contract says so. Correct?

A. That's true. The one piece of it you left out is that the EDCs don't eat that cost or get that windfall, that's passed on one way or the other to the Standard Offer Service customers.

So they're part of the transaction, of course, but [14] you left one piece of the back and forth out. But everything else you said is correct.

Q. In the sense the EDCs costs are passed on to ratepayers under Maryland retail transaction –

A. But I didn't want to create the impression this was a cost that was going to be borne with the EDCs with no recourse on their part.

Q. Okay.

A. It's important—it's an important piece of the yin and yang here, because the analysis that we performed is set forth in the files that Boston Pacific reports, so there's nothing behind the curtain here, showed how the relative economics of that—of that transaction were likely to work out for the company and the ratepayers.

Q. Okay. Let's turn back to the contract for a moment, at attachment A to the RFP?

A. Okay.

Q. I don't want to discuss this in detail, but I just want to make sure we're on the same page here. You're familiar with the terms of this contract, correct?

A. I am. Still generally familiar with them, yes. I won't represent to the Court that I have committed all of it to memory.

Q. Fair enough.

So within the framework of this contract, the [15] counter-party to the EDCs, the new generator, is referred to as the supplier; is that right?

A. I think so. But it's defined in here somewhere.

Q. Just want to make sure, if I use that word, I want to make sure we have a shared understanding?

A. Okay. We can go with that. It's knowable.

Q. The contract requires that the supplier, the new generator, come into operation and participate in PJM's energy and capacity and ancillary service markets, correct?

A. I know it requires them to participate in the energy and capacity markets. I'm not as a hundred percent certain about ancillary services market, but the contract will say whatever that is.

Q. And the contract says that that participation is subject to guidelines that the Public Service Commission is going to promulgate?

A. Yes.

Q. We don't know what those guidelines are yet, do we?

A. When I left on Monday the seventh of January, they had not yet been promulgated.

Q. And the contract requires that participation in the energy markets is in a manner that involves the supplier making cost-based offers?

A. Yes.

Q. Okay.

[16] A. Like every other participant in the energy market.

Q. I'm sorry, is every other participant subject to a Public Service Commission enforced contract?

A. No. But I think generators that clear in the capacity market are required to make cost-based offers. Under PJM standard. I may be mixing some energy apples and capacity oranges, but –

Q. And—

A. Those rules are going to be whatever they are.

Q. So the supplier under this contract owes an obligation of physical delivery of energy?

A. Yes.

Q. And the supplier has an obligation of actually selling its capacity by having it cleared in the PJM auction?

A. Well, it's got to bid the capacity into the PJM capacity auction. According to the rules governing the PJM capacity market as set forth in PJM's tariff as was proved by the FERC, and they don't get paid unless they clear.

So they can bid and not clear, that doesn't—that could happen. But they don't get paid unless they clear.

Q. Okay. And the contract prohibits the supplier from selling its capacity or energy to anyone else, anyone else other than in the specified markets that the contract says they're obligated to participate in?

A. Yes. Just like any other bilateral contracts that happens [17] every day that PJM works yes.

Q. Bilateral contract for sale of energy and capacity?

A. Yeah, bilateral contracts can cover all those things, and they're billions of them happening in PJM all the time among parties. Throughout—throughout the RTO, and that is a common feature.

If you're buying something, you would certainly hope that the seller isn't selling it to somebody else simultaneously.

Q. Okay.

A. Otherwise you're paying—never mind.

Q. Well, maybe you were about to complete this thought, in fact, it was important to the Public Service Commission that this new project actually sell its energy and capacity?

A. The purpose of the docket, the purpose of the order, was to solve a long run reliability concern by having new generation built in our state.

So physical construction and physical delivery of electricity was a central component of the docket, the raison d'etre of going down this path. Having some new fancy financial transaction would not have helped us. We needed more juice in Maryland.

Q. Thank you.

Your Honor, I just—that last answer raises a question that I think is appropriate for us to address sooner [18] rather than later.

I did ask the question, and I appreciate the answer. When I asked at the deposition, asked questions like this, questions about why it's important to require that CPV actually sell energy and capacity, Mr. Erwin objected and instructed the witness not to answer those questions under the deliberative process privilege.

Now, the witness clearly has views about why it's important for all of these terms to be in the contract. But I don't want to learn them for the first time here today.

Because it's fundamentally unfair not to be in a position to prepare for litigation to have them be able to provide their side of the story without any ability to question it.

THE COURT: At the fear of being—if you don't want to learn it, don't ask. I don't know that he wasn't volunteering an answer to a question that wasn't asked. But do you want to move to strike his answer? It seems to me that the purpose that was expressed by Mr. Nazarian.

MR. MEYER: No, Your Honor, as to this issue, it's—this is not a particular—not an important point. I just wanted to raise the point that if we ought to have some ground rules here that if the witness has been precluded, I think Your Honor's already ruled to this effect, if the witness was precluded from testifying, providing answers to questions at his deposition, and he was instructed not to cross a whole [19] array of

topics relating to the orders and the contracts and the RFP, the Public Service Commission ought to be precluded from offering evidence whether—

THE COURT: I think—

MR. MEYER: In response to my questions.

THE COURT: As a motion in limine, I think it was granted, and I don't think there was any debate about it. At this point, Mr. Nazarian, it would be different if he were responding to these questions by the other side, because he's responding to your question.

MR. MEYER: I understand, Your Honor, thank you.

THE COURT: Okay.

BY MR. MEYER:

Q. So with respect to the particular way in which the contract guarantees the supplier a fixed revenue stream over the long-term, as you've already described, it does that with respect to sales of capacity by saying to the EDCs whatever CPV makes from PJM when it sells a MW data of capacity, you EDCs will make up the difference between that and the specified contract price, whatever that price is?

A. Generally speaking, that's true. I mean, there are a lot of details and moving parts in this. But generally, you captured the general structure of it. The contract says to the developer, if you build a plant and clear it in the capacity market, and you operate it pursuant to PJM's dispatch rules in [20] the energy market, you'll be entitled to a certain stream of revenue that's agreed in the contract. You're also going to be required to sell that electricity into the various markets and collect that revenue.

If you collect less than the contract price, the investor-owned utilities will pay you the difference and pass that off on to standard service ratepayers. If you get more for the electricity than the contract price then you'll pay that difference to the investor-owned utility companies, who will then pass it on to ratepayers over the 20 year life of the contract.

There are projections whether that would be a positive or negative proposition in different years. Structurally that's how it was meant to work. There are a lot of intricacies within the contract about how things get counted and different markets and different components of it, but that's the overall structure of it.

Q. Okay. So if you could look at tab 11, I'm sorry, at plaintiffs' 241 in your binder.

A. I don't have plaintiffs' 241.

Q. I'm sorry, it was misidentified in my notes. Plaintiffs' 215?

A. That, I do have.

Q. Do you recognize this document as the response by CPV Maryland to the RFPs that were issued by the EDCs in response [27] consultants on the ultimate economics for the ratepayers of going forward with the CPV proposal.

THE COURT: When the proposals came in from the interested parties, did those proposals include a proposed contract price?

THE WITNESS: Yes.

THE COURT: Okay.

THE WITNESS: Mr. Meyer showed me before the pages in the blank RFP that had all the empty charts

in it, and so the bidders were all required to fill in those charts with their proposed numbers.

And Boston Pacific then crunched all of that and prepared a recommendation for us that's in the public file in the case.

THE COURT: So Boston Pacific, was there more than one proposal from more than one supplier?

THE WITNESS: Yes.

THE COURT: Okay. That's all. Okay. So Boston reviews this and comes up with a recommendation that the contract price should be X?

THE WITNESS: Well, it was a recommendation that the—based on, based on the record we had developed in January in our hearing on the reliability questions, the extent the potential need of how many MWs we as a state might need, Boston Pacific made a recommendation to accept the one proposal and [28] reject the others. So they didn't say set the contract price here. They recommended that we accept one proposal and not accept the others.

THE COURT: So that it was CPV submitted their proposal and included a contract price of X?

THE WITNESS: Yes.

THE COURT: And then they submitted with a price of Z, et cetera, and Boston Pacific said we recommend you accept CPV And therefore you would accept their price?

THE WITNESS: Correct. And then there were others that had prices at Z, A, B, and C, or however many there were, and I'm not disclosing how many.

THE COURT: Why do we need any more than that at this point?

MR. MEYER: I just have one follow-up question. I don't think we need much, Your Honor. Especially what I was trying to establish was the Public Service Commission ended up entering an order that set a price in a contract, and Judge Nazarian, there was no evaluation by anyone of what the likely relationship would be between the capacity contract price and market levels of capacity prices.

MR. ERWIN: Objection, Your Honor, to the extent he's asking about what the Commission evaluated. To the extent he wants to limit it to the consultants or anybody else, it's an okay question.

[29] THE COURT: Well, Mr. Nazarian, start with that limitation.

THE WITNESS: I don't understand the question.

BY MR. MEYER:

Q. My question really is this –

A. If you're asking did we try to figure out what level of revenue it would take for some developer to build with or without a contract, is that what you're asking?

Q. I know I asked you that question in your deposition, and you said no, correct?

A. Not in a proceeding. Nothing, so, no. But we don't have the ability to do that. Developers are private companies. They – I can't get in the heads of a developer and know what they are or aren't going to need or what their investors' expectations are what their board would approve or anything like that. That would be rank speculation.

Q. Which is why you let the developer specify the price that it said it needed, correct?

A. It's why we held a competitive bidding process and let developers bid competitively. And we value – we had our consultants evaluate the competitive bids to determine whether it was a positive economic proposition for the ratepayers over the life of the contract. If it had not been, if it had been a bad deal, we were not obliged to accept any of them. If we'd gotten a bunch of greedy developers who came in to look to make [30] too much money on the backs of the ratepayers, we would have said no.

Q. Let's talk about this competitive bidding process. The RFP, plaintiffs' exhibit 2, establishes a series of criteria that limit who may participate in the bid process, correct?

A. No.

Q. No?

A. It says parameters for what the proposals had to contain. It didn't say anybody could or couldn't.

Q. Okay. So the proposal, though, the only proposals that would be acceptable were ones that involved a construction of a new generating facility, correct?

A. I believe it was a new gas-fired power plant physically located in the SWMAAC region of PJM.

Q. Okay.

A. And there are probably some other parameters too we could find in there.

Q. Referring to page 4 of the RFP, in the product definition of section 2.1?

A. Yep.

Q. That may have been what you were thinking of?

A. Well, I was thinking about it more broadly, but it's all in there.

Q. Okay. And so let's take a look and break that down. The products under what is acceptable under the RFP, the energy and [31] capacity that's acceptable under the RFP must be from a generation capacity resource that, take the first one, is located inside the SWMAAC Locational Deliverability Area.

A. That's what it says.

Q. A proposal from a project outside of the SWMAAC Locational Deliverability Area is not conforming?

A. Correct.

Q. Not allowed?

A. Not to this RFP.

Q. Right. And moving farther into that paragraph, it's also true that the generation capacity resources must be new, and are you familiar with – well, you are familiar with the concept of an uprate to an existing facility, correct?

A. I am.

Q. Where some amount of additional output capacity can be added at an additional plant?

A. Yes, I'm familiar with that.

Q. A proposed uprate or uprates that would add capacity would be non conforming and not be permitted to participate in this competitive—

A. That's true.

Q. —process?

Existing resources are also not allowed, someone with a power plant that generates 661 MWs that's already in the market, that has already cleared a Base Residual Auction in the [32] past, is prohibited from participating as well, correct?

A. It is because that's not the purpose of the RFP. The existing resources are existing. The goal is set forth in the orders was to add capacity.

So having existing power plants respond to this RFP would not have addressed the purpose.

Q. And the purpose it was also to add a specific kind of new power plant, a natural gas-fired power plant, correct?

A. Ultimately, we decided, yes, to limit it to new gas-fired power plants.

Q. So a plant that would burn coal or a nuclear plant would not be allowed to participate?

A. Ultimately not. In the earlier stages of the case, the first draft RFP was broader in terms of acceptable fuel sources.

We had a number of comments from different parties that it would make the RFP, and these are filed comments, Your Honor, so I'm not getting again behind the curtain here, filed comments suggesting that the RFP would be easier for people to respond to and to analyze if the range of fuel sources and other parameters were narrowed to make it a comparison of maybe Macintoshes to Golden Deliciouses rather than all sort of different fruits.

Q. Okay. Are you aware that in January of 2012, among the comments that the Public Service Commission received were [33] comments from PJM's independent market monitor?

A. We received comments from Dr. Barron on a number of different points, but I'm sure we got some in January as well.

Q. If you look at plaintiffs' exhibit 43, please?

A. Okay.

(Pause.)

Q. If you look at page 2 of those comments, first full paragraph, beginning the third line, the independent market monitor says the proposed RFP approach is not consistent with the operation of a competitive capacity market. The proposed RFP approach would have the following undesirable results:

The procurement of capacity that is not needed for reliability; the procurement of capacity through a process that is discriminatory because it excludes existing generation and non gas-fired units; and the requirement to offer the procured capacity so that it clears in the PJM capacity auctions.

Do you see that?

A. I do.

Q. If you look a couple of lines down in the same paragraph, the independent market monitor also said, I'm reading five lines up from the bottom of that paragraph, this would negatively affect the incentives to build new generation and would likely result in a situation where only subsidized units would never be built.

Do you see that?

[34] A. I do see that.

Q. On the next page, the market monitor provided a recommendation that refers to potential for non discriminatory competitive auctions.

Do you see that?

A. I—tell me where you're looking, but I'm familiar with Dr. Barron's views on this subject.

Q. Well, he distinguishes—at the bottom of that page, he distinguishes the market paradigm, carrying over to page 4, the market paradigm, that includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it's needed to incent retirement of units when appropriate. This approach will result in long-term reliability at the lowest possible cost.

Do you see that?

A. I do see that.

Q. Do you understand him to be referring to the market paradigm as it exists in PJM's energy and capacity markets, correct?

A. He's referring primarily I think almost exclusively to the capacity market, but, yes, I'm familiar with Dr. Barron's views on this, and we've had a healthy robust and collegial disagreement on all of these topics for a number of years.

Q. The Public Service Commission disagreed with those views?

[35] A. We did.

Q. Okay.

A. They're wrong. He's a smart guy, and he's involved in creating that market, but he doesn't

address the fundamental structural defects in the market that we've identified all along.

Q. And that your order was designed to address?

A. Yes. Within the rules set up for the market. The FERC, the FERC regulates the structure of the PJM capacity markets as well as the energy markets and everything else. RFP played within those rules. Dr. Barron's got a different view about what incentives will or will not materialize in the capacity market. I and my colleagues have respectfully disagreed with him, that the capacity market will ever send a price signal to anchor a long-term asset. It's a one-year signal, he believes, and a lot of people believe, and I suspect your clients believe, that if that one-year capacity price is allowed to go high enough, companies and financial institutions will make long-term decisions about investing in power plants.

The testimony we've heard repeatedly in our hearing room and the experience that we had over the last five years suggest that that's not true.

And so I understand everything that Dr. Barron is saying here, and I appreciate and respect his views, and I disagree with them, and my colleagues did the whole time.

[36] Q. When you say—to be clear, when you say played by the rules, what you're referring to is the fact that the new generation facility induced into the market by this order would be required when it sold its energy and capacity into PJM to follow whatever rules were in the PJM tariff; is that right?

A. All of them. Yes. Energy, capacity, ancillary services, no matter what. We don't regulate that stuff.

Q. And that's what you were referring to?

A. Yes.

Q. Okay.

A. We're allowed—state utility commissions for a hundred years have made decisions about what power plants should and shouldn't be built.

If you go to west, West Virginia, or other parts of PJM, they still do it that way. You can have resource planning in the traditional state role within the construct of these competitive markets.

And so that's—we have state law that says we're—the Commission is allowed to order investor-owned utilities to buy, build, lease or acquire new generation as needed to serve the anticipated long-term demand of the State.

That can be exercised only within the context of the wholesale electricity markets that exist and that are regulated by the feds.

And our RFP required that any winning bidder follow [37] those rules.

Q. The states you referred to are what you would describe as non restructured states; is that right?

A. Yes.

Q. We may come back to that in a little while. So let me ask a question specifically about this SWMAAC locational requirement that we saw in the RFP.

After the RFP, I believe it was after the initial RFP was issued in—there was an RFP in September that was issued, and then a revised RFP was ultimately the final RFP issued in December of 2011?

A. That sounds right.

Q. And during the course of that process, there was a question and answer, an opportunity for potential bidders to submit questions to the Public Service Commission about how the RFP and the contract would function?

A. A pre-bid conference, yes.

Q. Okay. If you could turn, please, to plaintiffs' exhibit 79?

A. Okay.

Q. This is—do you recognize this document as a series of questions and answers that relate to that consultative process? A. Yes, I do.

Q. I want to direct your attention to page 5 of 6, and question number 17

[38] A. Okay.

Q. Question number 17 refers to a section of the RFP requiring that the generation capacity resource be located within SWMAAC. And the question is, does the generating equipment need to be physically located within the SWMAAC at LDA, or can the plant itself be located outside of the SWMAAC boundaries as long as its interconnection point is located within the SWMAAC LDA? A. I see the question.

Q. Do you see that?

And the answer to that question was the generating equipment itself needs to be physically located within the SWMAAC LDA?

A. I see that, too.

Q. Do you know from whom this question was submitted?

A. No.

Q. Do you know whether there were generating facilities that could be located outside of SWMAAC, but close enough to SWMAAC for there to be an interconnection point?

In other words, wires from the plant into SWMAAC connecting it directly to SWMAAC?

A. I don't know. It may be possible. But I don't know.

Q. You do know, or you did understand that a plant right over the border of Pennsylvania might not be all that different from a plant right over the border in Maryland, might be electrically the same, correct?

[39] A. Yes. But the problem is you can see it on the big map over there that shows the zones. MAAC is a very big zone. And it's challenging in an electrically neutral and reasonable sort of way to define what would be close enough to be helpful without also taking in all sort of plants that might not be helpful. So SWMAAC, which is where the overwhelming bulk of the people live and the load is, and is a zone created by PJM. There's a long history we can talk about, if you want or not.

But it's an electric zone defined by PJM, which happens to be where the reliability concern was. If you go outside of SWMAAC, you can see on the map, the MAAC region, and EMAAC region go a long way.

I would not agree that a plant anywhere in MAAC or EMAAC would be just as helpful to Maryland's reliability problems.

So it's a function, and we're getting quickly out of my physics and engineering depth, Your Honor, but there is a correlation between the distance.

And then it gets into transmission capacity and what wires are where in different places. And so it gets more complicated.

But to your earlier question, a plant that's a couple miles over the border in Pennsylvania might be about as helpful or nearly as helpful as a plant a couple miles on—inside of Maryland. But from there, it's hard to generalize.

[40] Q. Do you know that northern border of SWMAAC is the Mason Dixon line, right?

A. I do.

Q. Electrically, there's nothing magical about the Mason Dixon line?

A. No. It's all about the history of the utility company territories that comprise it. So SWMAAC is comprised of BGE and PEPCO territories, which includes those two service territories in Maryland and the District of Columbia.

Everything in PJM, all those funny-looking boundaries, are a function of utility company territories and how they were built and how they evolved. I don't think there were any wars over it, but there were—it's all in how different companies sprung up and organized their systems and it's also—it's all electrical.

Q. Thank you.

So I want to shift gears and talk to you about Maryland's restructuring.

A. Okay.

Q. We've already touched on the fact that Maryland is what we've described as a restructured state?

A. It is.

Q. And restructuring occurred in 1999 with the Electric Customer Choice and Competition Act?

A. That was the year of the legislation. It played out over the next year or two, but yes.

Q. Prior to restructuring, Maryland's electric utilities, that are now the EDCs, were integrated and regulated on a rate base approach, correct?

A. Yes.

Q. So the generation assets, the distribution assets, and retail sales, were all part of a single unit, the integrated public utility?

A. Generation transmission distribution, yes.

Q. And that utility was regulated by the Public Service Commission?

A It was. There were elements of what they did that were regulated by the FERC, but yes.

Q. To the extent that that utility engaged in wholesale transaction, those wholesale transactions would be regulated by the FERC?

A. Yes. To the extent they were operating in interstate commerce, yes.

Q. And one of the things that restructuring did was to separate the generating assets from the utility from the distribution company?

A. The latter is more accurate, yes.

Q. The distribution company?

A. From the distribution company, yes, sir.

Q. Utility is a term of art under the Federal Power Act, maybe [42] I'll stop using it.

A. Well, it means a lot of things to different people, but I want to be sure I answer your question correctly.

Q. So you're comfortable with the term EDC, Electric Distribution Company?

A. I'm familiar with it. We'll use whatever one Judge Garbis wants, but yes.

Q. Okay. So and one of the purposes of restructuring was to enable there to be competition among generating companies to sell the output of generating facilities to the electric distribution companies?

A. I think I got lost a little bit in there somewhere.

One of the overarching goals of restructuring was to separate, as you pointed out previously, separate generation and transmission and distribution and create opportunities for retail electricity competition so that customers could buy their electricity from whomever they wanted rather than from only their electric company.

Q. So let's—

A. And then it was meant to disengage generation risk from rate base and create a world where competition would flourish, all sorts of ideas like that, most of which have not panned out.

Q. Fair enough. It's obviously a lot of complexity here. But let me just make sure we're focused on what you just described

* * * *

[51] clarification, where—in pre-restructuring, where the electricity was being generated by the utility, all right, and delivered directly to end users, there was no wholesale transaction, was there?

A. I don't know. Let me try it this way. The end user still got a bill from BGE that covered all those things. And there was no opportunity for that end user to go buy electricity from somebody else. There could well have been wholesale electricity transactions that BGE was engaged in.

Q. Well, as an example?

A. It's before my time, so I don't want to be definitive with you about it.

Q. Just to be clear, the other illustration you provided of BGE going out and procuring energy from a supplier outside of the State of Maryland, that transaction would be a wholesale transaction?

A. That would have been, yes.

Q. Because BGE is acquiring that energy in order to resell it to its end users?

A. Right. Like any other wholesale transaction, except it's regulated closely by the FERC.

Q. Okay. Now, if I could direct your attention to plaintiffs' exhibit 606.

This is an order of the Public Service Commission in May of 2007

[52]A. Yes.

Q. And do I recall you saying that's before your time?

A. I was a citizen when this order was issued, but it was one of the first things I read when I got hired.

Q. You're familiar with this order?

A. I am.

Q. Okay. And this order addresses a number of issues relating to the consequences of restructuring of the electric power industry in the State of Maryland?

A. At a very high level, that statement is true, yes.

Q. If you turn to page 36, there's the background on the 1999 restructuring law. And then on the top of the next page, page 37, there's a description of the three significant features of the 1999 act that accomplished restructuring.

Do you see that?

A. I see it.

Q. Okay.

A. I'm reading it for the first time in probably six years, but I'll read it.

Q. I'm not going to ask you specific questions about that paragraph, but feel free.

A. All right. I see that it's there.

Q. Okay. So and then below that, in that section, there's a heading "Reliance On The Wholesale Market"?

A. Yes.

[53] Q. And that section states one of the most fundamental changes brought about by the 1999 act was the removal of ownership of Maryland-based electric generating capacity from the traditional regulated utilities, such as BGE, and transferring ownership of those facilities and the electricity they produce to affiliated or other companies not directly subject to state regulation.

Do you see that?

A. I do.

Q. And that's describing what you referred to earlier as—we discussed earlier as separating the generating companies from the EDCs?

A. Yes.

Q. And then in the next paragraph, on page 37, this order says the two significant consequences of this legislative change were that the regulated utility, such as BGE, and now there's the use of the word utility, that's the EDC being described there, right? Would need?

A. I think so.

Q. Would need?

A. Go ahead.

Q. Would need to rely directly or indirectly on the wholesale electricity markets to provide electricity to its customers because it no longer owned any generating capacity.

And, two, actual rates paid by customers would be [54] largely driven by wholesale market conditions in large part outside the direct supervision of the Commission.

A. It says that, yes.

Q. That's what the Public Service Commission wrote in this order?

A. Yes.

Q. And then on the next page, there's a discussion of FERC's role in monitoring the wholesale market?

A. There is.

Q. And there's a statement there that FERC's jurisdiction extends to such wholesale transactions and to entities that transmit electricity in interstate commerce or sell wholesale generation without regard to ownership of those facilities.

Is that referring to Section 201 and 205 of the Federal Power Act, correct?

A. That's what it says.

Q. And then the next paragraph, under federal FERC, not the Commission, has the responsibility to ensure that there's enough competition and discipline in the wholesale markets so the rates paid by electric consumers reflects wholesale generation prices that are within a zone of reasonableness and not inflated by market power or collusion.

A. It says that, yes. It would be clearer to say that it relates to the supply rates, but yes.

Q. And in the next paragraph, the Public Service Commission [55] also notes that FERC has jurisdiction over all transmission owners to ensure that wholesale transmission service needed to support competitive markets will be provided at just and reasonable rates and FERC also has jurisdiction over RTOs, such as PJM, that provide wholesale transmission service and perform other functions under order 2000, such as operating wholesale generation markets including sales of energy, capacity, and ancillary services.

A. It says that, yes.

Q. Now, there came a time not terribly long after this order was issued, that there was concern in the Maryland legislature with the consequences of restructuring, or is it fair to say—is it fair to describe restructuring as equivalent to deregulation?

A. Many people do. I think those terms are generally understood to be the same thing. The legislative interests came before the issuance of this order. But it's in the same middle part of that, whatever we call the last decade, the oughts.

The legislative interests really cranked up in 2006, and this order was 2007, but it's whatever.

Q. Let's go to plaintiff's exhibit 162.

A. I'm sorry, 162.

Q. 162?

A. Okay. Okay.

[56] Q. This document is a presentation that you delivered as Chairman of the Public Service Commission in July of 2009?

A. Yes.

Q. To something referred to as the EEI/ICF Transmission and Wholesale Markets School?

A. Correct.

Q. And in this presentation, you delivered views regarding the regulatory landscape as it affected generation and transmission?

A. To very a very high level, yes. This was meant to be, this school, EEI is the Edison Electric Institute, is the industry Electric Industry Trade Association, ICF is a consulting firm, I don't know what it stands for. But they put on this school for FERC staff and for company staff to introduce them to different elements of the marketplace. And I was asked to do presentation on wholesale markets and transmission generally.

Q. Okay.

A. And that's what this is.

Q. And I recall having this difficulty when we were together at your deposition, these pages are not numbered. So I'm going to refer your attention to the fourth page.

A. Okay.

Q. At the top it reads the Maryland Example. And under the heading Generation and Supply, you note since restructuring, the Commission no longer regulates existing generation [57] directly.

A. Yes.

Q. And in the sub bullet, you say new generation could be built and owned by utilities and regulated, but the law contemplates, and the law here is referring to the Maryland's Restructuring Act, right?

A. Yes.

Q. Contemplates that merchant plants will be the norm?

A. That's what it says.

Q. Now, on the next page, continuing the discussion of generation and supply, the first bullet says that the Commission exerts indirect influence through advocacy at PJM and FERC?

A. Yes.

Q. You also discuss transmission in this presentation?

A. I do.

Q. In the next, I believe the next page.

A. Next couple.

Q. The beginning on the next page?

A. Yep.

Q. You referred to transmission planning as a function of PJM, first bullet under transmission says PJM performs regional transmission planning, do you see that?

A. Yes, I do see that.

Q. And under the next – the first bullet under that heading [58] PJM focuses on reliability, not economic impact, projects and timing are all about reliability violations, not rates?

A. Yes. That's true.

Q. And then turning two pages farther, you describe the authority that the Commission retains over generating stations and transmission projects.

You say the Commission has siting authority over generation stations and transmission projects within Maryland?

A. Yes.

Q. With respect to transmission projects, there is a need assessment?

A. Yes.

Q. In other words, one of the things that the Public Service Commission evaluates in determining whether to approve or disapprove a proposed transmission project is the need to meet existing and future demand for electric service?

A. Yes.

Q. With respect to generation stations, Public Service Commission does not evaluate need?

A. Correct. That was one of the changes of the restructuring law.

Q. Right. And you in fact note in the next paragraph, next bullet under restructuring, need for new generation is determined by the marketplace?

A. Yes.

[59] Q. And that's the wholesale marketplace?

A. Yes. I suppose I could have been more complete and noted our residual authority under Senate Bill 1 to order new generation in anticipation of a long-term demand in the state, but yes.

Q. So now you described the fact that even prior to the order that we looked at in the 9099 proceeding, there had been concern that restructuring or deregulation had not worked well for the State of Maryland?

A. Yes.

Q. Let me direct your attention to plaintiffs' exhibit 391.

A. 391.

Q. 391?

A. Okay.

Q. Do you have the document?

A. Yes, I'm sorry, right there with you.

Q. And this document is a report that the Public Service Commission of Maryland provided to the Maryland General Assembly in response to something referred to as Senate Bill 400?

A. This is one of a series of things, but yes.

Q. This is the interim report?

A. This is part of the interim report. This is the portion of the interim report that the Commission itself wrote. There were other portions provided by consultants the Commission [60] retained.

Q. Okay. And Senate Bill 400 was signed into law in May of 2007?

A. Yes.

Q. And asked the Public Service Commission to study re-regulatory options and report back to the legislature?

A. Yes, among other things.

Q. And then the Public Service Commission reported back with an interim report in December of 2007, which is the document that we're looking at?

A. We—yes. We were directed in Senate Bill 400 to file an interim report December of 2007 and a final report in December of 2008.

So what we did each year was put on top of it all a Commission report and then separate reports from two groups of consultants, one from a law firm called Kaye Schoeler, and one from an economic consulting firm called Levitan and Associates. So each year they got a package with three reports.

Q. Okay. The portion I think you said this, just so we're all clear, the portion of the interim report that the Public Service Commission itself wrote is the document you have in front of you?

A. Plaintiffs' exhibit 391 is the Commission portion of the interim report in December, 2007, yes.

Q. Okay. And this interim report, turn to the next page, the [61] first page, in the first paragraph, offers

that the Public Service Commission's recommendations and analysis regarding options for re-regulating Maryland's electricity markets and for obtaining new generation and transmission resources in our state?

A. Yes.

Q. And the legislature, when it promulgated SB 400, was unhappy about the level of rates that deregulation had brought? A. They were unhappy about a lot of things, but that was one of them.

Q. The Public Service Commission evaluated an array of options for re-regulating Maryland's electricity markets and obtaining new generation resources within Maryland?

A. That's fair.

Q. One of the options was a return to the pre-restructuring regime, cost of service regulation?

A. Yes.

Q. And utility ownership of generation?

A. I know—I know we absolutely did that in the '08 report. I have to look in here and see if we said that in '07, if I would find it, it's going to be in there or not.

Q. Okay.

A. I do remember we made—we analyzed that in the final report of 2008. It wouldn't surprise me if we did it in '07 as well.

[62] Q. Ultimately, though, you did recommend that?

A. Ultimately, we did not.

Q. The recommendation, if I might direct your attention to paragraph—to page 31 at the bottom, orient the discussion, there's options for re-regulation?

A. Yes. Okay. There you go.

Q. And then on the top of the next page, option one, utility ownership of all in-state generation and return to cost of service regulation?

A. You refreshed my recollection, yes.

Q. Okay. Option two on page 33 was utility directed long-term contracts?

A. Yes.

Q. And the concept there, in general terms, is ordering the State's utilities, what we've discussed as the EDCs, to enter into new long-term contracts or into long-term contracts for their generation?

A. Yes.

Q. Now, on page 34, in this report, to the legislature, in the last paragraph before the next heading, actually appears to be—contain a typo in the heading, but referring to the last paragraph, Public Service Commission reports given the information presented in both reports—and that's referring to the consulting, the reports of the consultants, and the testimony received in hearings before the Public Service [63] Commission, particularly case number 9117 Phase II, we conclude that the best alternative for ratepayers appears to be directing utilities to issue RFPs for long-term contracts for some combination of new in state capacity, energy, or both.

A. Yes, it says that.

Q. That was the recommendation?

A. It was.

Q. And if you turn to page 41?

A. That was the recommendation in the context of the question we were asked, by the way.

Q. Okay. If you turn to page 41, at the bottom, you offer your conclusions regarding long-term utility contracts for new generation?

A. Yes.

Q. The analyses by Levitan and Kaye Schoeler combined, and those are the consultants?

A. Yes.

Q. Levitan and Kaye Schoeler combined to create a compelling case for directing utilities in the state to enter into long-term contracts to induce the supply of new electricity in Maryland. This is a re-regulation option that we believe should be pursued and that we intend to pursue.

A. That's what it says.

Q. Okay. I'd like to direct your attention to plaintiffs' 580.

[64] Plaintiffs' 580 consists of the slides used to deliver a presentation to the legislature concerning the recommendation in the interim report we just looked at?

A. Yes.

Q. And the Public Service Commission told the legislature on page 4 of this slide presentation that there were two goals of re-regulation. One was to maintain the reliability of the electric grid. Another to

obtain the best possible prices for Maryland ratepayers. And that there was a threshold question, will the market address the needs of Maryland's ratepayers?

A. Yes.

Q. Market being referred to as the wholesale market?

A. Yes.

Q. On page 12 of this presentation, you explained to the legislature that market conditions had caused high prices in Maryland?

A. Yes.

Q. The wholesale market?

A. Yes.

Q. And that, referring to the second bullet, wholesale market rules adopted by FERC and PJM exacerbate Maryland's high prices?

A. Yes.

Q. And referring to slide 19, you reported to the legislature regarding the impact of RPM on SOS rates.

[65] Now, there are lots of acronyms in this case. RPM is Reliability Pricing Model that PJM uses to administer its capacity markets?

A. It is the capacity market, but yes.

Q. SOS rates are the Standard Offer Service rates that are charged by EDCs to their retail customers?

A. Yes.

Q. And you were reporting to the legislature that RPM, the capacity market, had resulted in higher costs?

A. It added $500 million to cost of electricity in Maryland, yes, which was true. And it's only gone up since then. The next year it was up to 2 billion.

Q. And if you refer to page 26 of this presentation, and the discussion with the legislature on the options for re-regulation.

You describe some of the costs and benefits of directing utilities to enter into long-term contracts for new generation?

A. Yes.

Q. One of the costs that you identified and recognized was that doing so could discourage new merchant generation?

A. Yes.

Q. And new generation refers to generating facilities entering into the market without the benefit of a long-term contract that Maryland was ordering EDCs to enter into?

[66] A. Well, merchant generation is new generation coming in on its own without some sort of support from the regulatory paradigm.

I mean, you've got to put this all in the context of the question we were being asked by the legislature here. They were—they were reacting to the fire storm during 2006 when market rates jumped 72 percent in the BGE territory, which is the biggest in the state. They were asking the question whether they should change the law and turn around from their decision to restructure and adopt something else and go—either go all the way back, which turned out to be complicated, or do something else.

But they were asking themselves the question of whether they still wanted to be one of the 24 restructured states or go back to something approximating what the other—what 26 states still had, which is direct resource planning function by their state regulators.

And so that's the question they were asking themselves in the context of the advice we were being asked to give.

And so, yes, if they had changed the law and there was a bill in 2009 that went a lot farther down this path, although ultimately it didn't pass, to have the Commission making resource planning decisions through long-term contracts, then, yes, that would discourage new merchant generation for [67] all kinds of reasons. They may not have cared about discouraging new merchant generation, as we sit here four or five years later, there's still no new merchant generation in this state.

So you can ask yourself whether it matters, but yes, that was one of the potential impacts of going that route.

Q. When the Public Service Commission issued its order in this case compelling EDCs to enter contracts with a new generating plant, long-term contracts, did it consider the impact of its action on new merchant generation?

MR. ERWIN: Objection, Your Honor, deliberative privilege.

THE COURT: I guess I'll sustain that objection.

Q. I want to go back to plaintiffs' exhibit 391. On page 26. A. Okay.

Q. Right in the middle of the page, your report to the legislature says Connecticut provides a helpful example.

A. Yes.

Q. And you comment on the end of that page, I mean, end of that paragraph, excuse me, in short as in Maryland, the federal market pricing mechanisms resulted in higher costs for ratepayers in Connecticut while Connecticut ratepayers faced transmission constraints and inadequate in state generation and saw no relief on the horizon?

A. Yes.

[68] Q. Connecticut was a reference point?

A. It was. Connecticut, like Maryland, was looking at its lights going out if it did nothing. In 2007 we had PJM in our hearing room telling us lights were going to start going out under load projections at the time in the summer of 2011 and 12 if we didn't do something.

So Connecticut was a useful example. Connecticut solved its congestion constraint problem by building two gas-fired power plants.

Q. Right.

A. And I think the market—the wholesale market rules in New England are a little different, and I believe in New England ISO has authority to order generation in ways PJM doesn't. I can't swear to that.

Q. Well, in August of 2008, one of your advisers on the Public Service Commission, Anne Lindner, wrote you a memo describing and summarizing the key attributes of the Connecticut experience as it related to inducing new generation into the market.

Do you recall that?

A. I recall that she wrote a memo about Connecticut, yes.

Q. I direct your attention to plaintiffs' 379. Can you—I'm assuming you were interested in Connecticut's experience in part because of the way they went about inducing new generation into the market would be potentially instructive to Maryland's [69] objectives?

A. We were interested in Connecticut because New England was restructured just like Maryland is, and Connecticut had a similar reliability problem that it was trying to figure out how to solve.

So yes, we were interested in learning about how Connecticut went about trying to solve a similar reliability problem.

Q. And in fact Connecticut had done something that is described in this memo in some detail similar to what Maryland ended up doing?

A. I think so. It's been a while. But yes.

Q. Required their EDCs to enter into contracts for differences with new generators?

A. That sounds right. It's been a while since I got familiar with it, but whatever this memo says I'm sure is a fair characterization of what happened in Connecticut.

Q. Well, on page 9, there is a description of the contracts, that the Connecticut Department of Public Utilities, if I'm reading it correctly, DPUC?

A. Yes.

Q. Determined should be entered.

A. Yes.

Q. CfDE, the acronym used in this paragraph, includes a payment mechanism whereby the EDC pays the supplier a specified

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[99] boatload of comments from all sort of sectors. And one of the reasons it took a number of months before we issued follow up to this is because we had to sift through all of that.

So we had, I don't remember how many, but it was dozens, plural, of comments that came in, in response to this.

Q. Under this RFP, the 2010 version, in addition to an uprate at an existing facility being allowed to bid, a facility of any fuel type would have been permitted to bid?

A. That could be.

Q. And in addition to that, there was a different locational requirement expressed in this RFP?

A. Okay. I don't remember, but I believe you. I mean it's going to be in the docket, but I just don't remember off the top of my head.

Q. I direct your attention to page 15.

A. Okay.

Q. Under the heading Minimum Threshold Criteria?

A. Okay.

Q. Criteria governing the minimum requirements of the bidder?

A. Yes.

Q. In paragraph 5, the proposed generation capacity resource must be interconnected to the system such that the generation capacity resource's output may be infed to a node east of the western interface and deliverable to Maryland east of the western interface avoiding likely transmission congestion?

[100] A. That's what it says.

Q. Do you know what that means?

A. I know at a lawyer's level.

Q. Does that mean that a project in Pennsylvania could bid in response to this version of the RFP?

A. Maybe. I'm not sure. It's possible.

Q. And—

A. The point of this, and you've got a couple of maps up there that might be helpful, but there's a point in the west/east flow of the grid right around Frederick where things get congested, where it's sort of like I 95 goes from four lanes to two lanes, and the amount that can get through at any given time diminishes. That's a big congestion point in the life of this grid.

That I think was designed to try and define in some electrical terms the way a plant could address that congestion investigation, that reliability problem, because that transfer limit ,is one of the reasons why things get tight east of that district.

Q. Okay. I'd like to direct your attention now to plaintiffs' exhibit 203. And you've already testified that after you issued this—after the Commission issued this 2010 version of the RFP, it ran a

solicitation looking for a consultant and ultimately hired Boston Pacific?

A. Yes.

* * * *

[106] an hour and a half and possibly as long as two hours.

Hopefully, less.

THE COURT: Okay. All right.

Mr. Meyer, I guess we can't do much for Mr. Nazarian. I suppose we have to take a lunch recess, but why don't you target the break point around 1:00?

MR. MEYER: I'll do my best, Your Honor.

THE COURT: All right.

BY MR. MEYER:

Q. So now let me make sure I understand this issue around the recommendation of the Boston Pacific report to target resources located in Maryland and either in SWMAAC or in EMAAC. Do you recall, do you recall that recommendation?

A. It says it on the page here, yes.

Q. Okay. A resource in EMAAC could be in either Maryland, Delaware, Pennsylvania, or portions of Pennsylvania, or New Jersey, correct?

A. Yes.

Q. And when I asked you to explain at your deposition why the RFP as it was ultimately issued struck out EMAAC as an acceptable location, you were instructed not to answer that question, correct?

A. Sounds right.

Q. So let me direct your attention to plaintiffs' 156. Plaintiffs' 156 is a letter submitted by the Public Service [107] Commission to the Economic Matters Committee of the Maryland legislature in response to a series of questions that it had—that the legislature had asked the Commission?

A. Two years before, yes.

Q. In June of 2009?

A. Yes. Two years before, two and a half years before this Boston Pacific report.

Q. Understood.

And I'm referring to the response to question 14 on page, again labeled without a page number, but bearing a Bates number ending in 67

A. Yes.

Q. The question was does it matter whether such a facility is a new generating facility built in Maryland or is in an adjacent state but serves Maryland load wholly or partly other than the obvious considerations of the property tax base and employment?

The answer to that question is locating a lower cost generating facility within the transmission constrained portion of the Maryland will likely affect wholesale energy prices in the State and more than if the facility were located just outside of the State.

A. That's what it says.

Q. All right. And then question down, reading farther down in the answer—the Public Service's, question 14 goes to a [108] pricing signal that is one signature of PJM's electricity market locational marginal pricing reflecting the value of the energy at the specific location and time it is delivered.

A. Yes. It should have said energy market, but yes.

Q. Okay. To distinguish it from capacity?

A. Correct. Locational marginal pricing is part of the energy market.

Q. And the last part of that paragraph says accordingly, a generation facility within Maryland may have more of an effect on LMP and thus aggregate wholesale prices in the State than would a facility located outside of the State?

A. Yes.

Q. And then question 14 also discusses the Reliability Pricing Model?

A. The capacity market.

Q. Capacity market?

A. Yes.

Q. And it says SWMAAC, the LDA that encompasses the BGE and PEPCO service territories is a distinct LDA from any area outside of Maryland?

A. Right. And I—you caught me in my deposition on that, too, and I fessed up that we missed the part about how SWMAAC also encompasses the District of Columbia, but yes.

Q. Therefore, capacity that is located in Maryland can serve to keep RPM costs lower in the event the SWMAAC would have [109] otherwise separated from other LDAs in the PJM footprint?

A. Yes.

Q. Because of this, generators located in Maryland can have a larger impact on customers in the state

than generation located just across the border but can still be delivered into the state?

A. True.

Q. And in fact, in the course of preparing those responses, you communicated with another one of your advisers, Melanie Mosier, about this specific question?

A. She was our legislative affairs director, so it wouldn't surprise me if that were true.

Q. Referring to plaintiffs' 158.

A. Okay.

Q. An e-mail relating to ECM or Economic Committee?

A. Well, I'm not copied on this, but—

Q. Pardon?

A. I'm not copied on this, but yes, I see it.

Q. Well, in the second e-mail from the top, Miss Mosier reports Doug—and Doug is you?

A. I assume so.

Q. Just articulated another good point.

A. Then it's definitely me.

(Laughter)

Q. About the fact that Pennsylvania is not in SWMAAC, that can [110] be relevant in the event SWMAAC separates from the rest of MAAC in RPM, another reason why generation located in Maryland could have a bigger impact on wholesale prices here than generation located outside?

A. Yes. It says all of that. And it might well have been something I said. And it happens to be true. And

it came up in the context of a completely different question we were asked by the General Assembly than anything that brings us back together today.

That e-mail exchange is months before case 9214 was even opened.

Q. Let me—let's try to shorten up what we have here.

Let me refer you to plaintiffs' exhibit 590.

Actually, you know, I'll save us the time. I'll skip that. Skip over that, try to complete before lunch.

Judge Nazarian, Public Service Commission had regarded the capacity prices resulting from RPM being instituted in 2007 as unreasonably high, correct?

A. At different times, yes.

Q. When you say at different times, you mean at various times?

A. At various times, yes. At other times, it was higher than it should have been, because rules were changed in ways that caused our zones to clear separately from the rest of the RTO.

I mean, there are a million things that are wrong with RPM, the result of which is generally that prices are [111] either too high or higher than they should have been.

Q. And referring to plaintiffs' exhibit 108, in May of 2008, the Maryland Public Service Commission, perhaps misidentified by your lawyers in the cover letter, filed a complaint at FERC?

A. We did. One of many.

Q. And this is a complaint in which you alleged the prices resulting from the first several auctions run under the RPM model were unreasonably high?

A. They were, by $12 billion, 2 billion of which is attributable to Maryland, yes. And the reason was that those transitional auctions could not have possibly served the purpose that they were intended to serve.

Q. In fact, in your complaint, referring to page 57, you gave some explanations for why prices were unreasonably high in your view?

A. Yes.

Q. One was that PJM, look at the heading on the top of the page, applied unduly conservative capacity requirements?

A. Yes.

Q. That increased prices, unduly conservative capacity requirements referred to requirements for excess capacity?

A. Yes.

Q. And looking at the paragraph under heading number 1 on this page 57, RPM establishes a demand curve that's farther to the right than where Maryland believed it should be, calling forth [112] more capacity than is needed to meet reliability requirements? A. That's what it says. There's a robust debate in the world of wholesale markets about what level of capacity should be procured in these markets. And there has been a lot of dispute about whether the markets over procure, which has the effect, since everybody gets paid the same price, of cranking up the price for everybody, including resources that have

been around for a long time, were built in rate base and have no risk.

It depends on what your market is trying to accomplish. If your market is really trying to accomplish the process of incenting new generation, you'd structure it one way.

If its purpose is to just give money and provide revenue surety to the resources that are already there, you'd structure your market a different way.

This complaint was premised on the fact that RPM is a three-year forward, one-year capacity construct that was ramped through and transitioned with these three auctions that were conducted either in real time with or way less than, way fewer than three years before the capacity planning years at issue.

So it was a total giveaway. It was just money that was paid to resources for decisions they had already made years before.

Q. And you believed, the Public Service Commission believed that RPM, Reliability Pricing Model, that PJM administers was [113] designed primarily to serve the objective of rewarding existing resources?

A. Yes.

Q. And you would have structured the wholesale market differently if the objective was to bring new facilities into the market?

A. Yes.

Q. So in your view, bringing new facilities into the market required doing something different from the way the capacity market was structured, correct?

A. There are all sorts of things different, yes, including quite possibly not even having a capacity market or, in my view, not re-regulating or deregulating in the first place. But that's a different conversation for a different day.

Q. Direct your attention to plaintiffs' exhibit 474, and I'm almost done.

This is another filing by CPV in that 9149 Gap RFP proceeding?

A. Yes, September, 2008.

Q. And CPV here is complaining, if you look at page 2, about the approach that the Commission was following in 9149.

A. Yes, they had a point of view. They had a power plant they wanted to get financing to build, and they wanted us to pay for it.

Q. Well, on page 3, they actually make a different point. If [114] you look at the first full paragraph on paper 3, they do say the first sentence the issuance of a short-term gap RFP plainly does nothing to facilitate much less promote the continued development of advanced projects, such as St. Charles in Maryland.

They go on to say more fundamentally, however, if implemented, it actually will jeopardize the viability of any effort to develop new combined cycle and or other baseload generation in the State, because it would significantly delay and materially dampen the very market signals needed to justify such investments.

A. That's what they say.

Q. And those market signals would be signals sent by the level of prices in the wholesale market?

A. If you believe the theory, and I don't, that the one-year capacity clearing price signal RPM will say to a developer come build your 20, 30, 40, 50 year asset in a place where the prices spiked up this year, then CPV's argument makes sense.

From that day on to this day and to my grave, I will believe that that will never, ever, ever work.

Q. You do understand that is one of the purposes of the whole RPM construct?

A. I understand that the RPM proponents argue that, yes. And I believe it is mistaken, and it has not worked.

Q. And those proponents include PJM and—

[115] A. Your clients.

Q. And—

A. And the people who had their generation plant built at rate base, yes.

Q. And RPM has been approved by FERC?

A. It has, which is a mistake, and they've compounded the mistake by continually changing the rules in response to requests from players like your clients.

Q. Fair enough. But let me ask you in your April 2012 order, it doesn't discuss anywhere the potential for your action to delay or adversely affect those market price signals?

A. Right, because that order had nothing to do with that. The order, if you read it, will tell you that it was designed under state law to resolve, or address at least, a finding that there was a need for additional

generation to serve the long-term demand for electricity in the State of Maryland.

That's a different question. And our April order plays in the wholesale construct the way the rules are set up by FERC.

Looking in the post restructuring era, regulators, utility regulators in restructured states get to wear a couple different hats.

We get to wear the one we wore for a hundred years where we made all the additions we made. But we also now get to go be advocates at PJM and at FERC and the federal [116] regulatory arena, because that's where the decisions that make up 75 or 80 percent of your electric bill get paid.

And if we don't speak up, and if we don't participate in those processes on behalf of our state, other than the office of counsel, which does its best, the voice of the ratepayers and citizens of Maryland will not be heard in the swirl of 700 stakeholders, all of whom who have financial skin in the game.

And what has happened as a real world practical matter is that the FERC has stepped back from regulating these markets the way regulators regulate things, and has delegated to the RTO stakeholder process, this negotiation, where, again, the theory is everybody who's got a skin in the game will come together and work it all out.

In that process to which the FERC defers heavily, the loudest voices are the ones of the parties that have the most financial interest. And so we decided in 2007 that our Commission needed to get visible and loud in those spaces in order to serve that role.

And so, yes, we have taken very strong positions to the point of being obnoxious where necessary.

But when the FERC decides what the rules are, the FERC decides what the rules are. And our order in case 9214 followed those rules, as it had to.

Q. Judge Nazarian, had you known or believed that the action [117] of the Public Service Commission would dampen the price signals or render the price signals of the market ineffective, you wouldn't have cared because, as you told me at your deposition, you regard RPM as not sending any incentives to investors and being useless?

A. I am sure—

MR. ERWIN: Objection, objection, Your Honor, deliberative privilege and calls for speculation.

THE COURT: I guess if Mr. Meyer is saying what Mr. Nazarian said in his deposition, then he can say that.

THE WITNESS: Well, he asked me that question, Your

Honor, in the deposition, in general, and I—I said it, and I believe it, as a general matter of market theory. In response to—I can't answer the question about the RFP without going behind the curtain.

MR. MEYER: Fair enough, thank you.

THE COURT: All right, folks, I guess 5 after 2, Mr. Thompson?

(Luncheon recess.)

THE COURT: Thank you. Let's proceed.

CROSS-EXAMINATION

BY MR. ERWIN:

Q. Thank you, Your Honor.

Judge Nazarian, with your permission, for the balance of my examination, I'd like to refer to you as Chairman

* * * *

[121] Q. Basically restructured or deregulated the Maryland utility industry in 1999?

A. No, no, that's not Senate Bill number 1. I don't remember the number of that bill. Senate Bill 1 was from 2006, but the '99 act, I'm aware of.

Q. The '99 act. At the time the legislature did that, did they include provisions leaving with the Public Service Commission some authority over generation?

A. Not to order generation. That was added in Senate Bill 1. In 2006 the authority that was left over generation had to do with siting, S I T I N G, new generation sources, and enforcing existing CPC.

Q. And they added that in 2006 in Senate Bill 1?

A. Yes. Among other things in Senate Bill 1, yes.

Q. And finally, Chairman, very early in your testimony, Mr. Meyer asked you questions about did the EDCs set a price in the contract for differences. My question to you is, did the EDCs set a price, or did the bids of the various bidders in response to the RFP set the price?

A. The bidder set the price.

Q. And that was an open competitive bidding?

A. Yes.

THE COURT: Let me just understand, Mr. Nazarian. The bidder submitted a proposal that had a price?

THE WITNESS: Yes.

[122] THE COURT: And then there was a review of it?

THE WITNESS: Yes.

THE COURT: Are you saying that when the decision was made to accept the package submitted by a company, I guess in this case, CPV, that that was the price or did the—did the price vary from what was in there?

THE WITNESS: The price did not vary, so we accepted the bid. Now, there were some terms and conditions of the contract that were still to be worked out, but the—there was no negotiation around price.

We put out the RFP. It had those charts in blank that you saw earlier in response to some questions Mr. Meyer asked me. The applicants filled those in.

Boston Pacific analyzed the results, and the Commission made a decision about whether to accept any of the bids. But there was no negotiation around price.

THE COURT: Okay. I'm glad you clarified that.

THE WITNESS: Thank you.

THE COURT: But they didn't—they didn't set price, I mean?

THE WITNESS: They proposed a price.

THE COURT: They proposed a price with a package?

THE WITNESS: Right.

THE COURT: And the price was accepted, it wasn't unilateral?

[123] THE WITNESS: Right. And the Commission retained the ability to select none. If the Commission had thought it was a bad deal, we could have not selected any of them. Or if we made a finding that there was no colorable reliability need that would be served by it, we could have decided not to accept any of the bids.

THE COURT: I assume the Commission could say a good package, but provision 27, you're going have to change 30 to 25 percent, because they could have varied the conditions?

THE WITNESS: That's true in some contexts, but not around price.

THE COURT: I understand that.

THE WITNESS: Yes, there were a number of provisions.

THE COURT: All right. Okay.

THE WITNESS: In the—in the draft contract that were under some continuing discussion among—first among the parties and Boston Pacific. And then when they reached an impasse, they would come to the Commission, there were two such hearings before I left. And to my knowledge, there's still one issue the Commission has before it about the terms of the contract.

THE COURT: But the premise was that the price that was bid is, it's going to be yes or no to that price?

THE WITNESS: Yes.

THE COURT: All right. Now, what that tells me, and [124] maybe there's just no dispute about it, is

that each bidder, CPV, made a judgment, and that judgment in order for us to build a plant, we have to—we have to have the guarantee of this price, and that's why we put in the number of X, and then they've done that with all their judgments as to their anticipated cost what they wanted to do for profits or what have you.

But it's their decision, if you want us to build the plant, we're going to have X dollars per unit?

THE WITNESS: Right.

THE COURT: Okay. That's fine.

THE WITNESS: Right. And it's over the 20-year life of the project. So it's—you know, they made whatever judgments they made about all the different factors including I'm sure because Boston Pacific looked at this, too, things like where they thought fuel prices were going to go, what they thought the electricity would be worth over the life of the contract.

So they made their judgments, and they bid their price, the Commission, through Boston Pacific, analyzed those bids and made a judgment.

THE COURT: Okay. That's great. Thank you.

MR. ERWIN: Thank you, Your Honor.

THE COURT: Do you have any more questions?

MR. ERWIN: I do, just a few.

* * * *

[149] deal with peak rewards.

If you get paid, if you cycle at 50 percent, you get paid $50 over that summer. So $12.50 each of the four summer months or maybe $10 each of the five summer months.

THE COURT: So it's not only the producer of electricity that says I can make capacity, but it can be a user who says I commit if you want to reduce the demand?

THE WITNESS: Correct. And just like the power plant has to be able to turn itself on when PJM calls, the demand response participant has to be able to turn the juice down when PJM calls.

And there's a whole flavor of companies out there called Curtailment Service Providers that do the same kind of thing.

THE COURT: The same clearing price because it's the same auction?

THE WITNESS: Yes. With a minor caveat that doesn't matter here, yes.

THE COURT: All right. Okay.

THE WITNESS: So they tote up all these resources, generation and demand response, and there's a way energy efficiency can participate, too.

So then—so by around February, first part of February, PJM issues the planning parameters for the auction, and the whole universe of generators and participants can look [150] at those plan parameters and know what they're bidding into.

In May, the second week in May, the auction is held. And at that point, everybody who wants to commit to be a capacity resource comes in, and they bid their price.

If you're a nuclear plant or a big baseload coal plant, and you want to run all the time, you'll come in and—or you want to make sure you'll clear, you'll bid zero because you'll know you'll get taken up front.

If you want to set a price below which you don't get taken as a capacity resource, then you can bid whatever you want.

When you look at a year like 2012, on this page 15 of defendant's 204, you can see the fact that the rest of the RTO cleared at $16.46 tells you that there are an awful lot of power plants in that zone that wanted to get taken no matter what the price was.

All right? And in that rest of RTO that all cleared like that is the very coal heavy and in Illinois nuclear heavy part of the RTO. Those are plants that want to run all the time. They want to get paid regardless and bid low and make sure they get taken.

Where you have parts of the grid that are transmission constrained like the eastern part of Maryland is, if you don't have enough generation or demand response within your zone to serve the entire forecasted load, then you're [151] going to have to import electricity from outside.

And the model will, again, will start at zero and move up the stack and take each successively more expensive bid until it buys enough to cover the load that it's forecasted.

If you're in a transmission constrained area, you may get to a point where the next cheapest resource is outside your zone. Right?

Now, if there were infinite transmission capability, it wouldn't matter. You could have load that Maryland gets served by another generator in Illinois and it wouldn't matter because any—any power could get transmitted anywhere across the grid. In reality, that's not true.

So there will come a point in SWMAAC, for example, as you move up the stack where the next cheapest available resource is outside your zone, but there's a limit to how much transmission can move more power into your zone, so you can't be served by that next cheapest one anymore. You have to go to the next cheapest one inside your zone. And that's when the zones separate, is when there's some transmission limit that prevents the next cheapest unit from being a capacity resource for you.

So when you see a separation here, I got it on 2-12-13 is the most glaring example, in MAAC, and in EMAAC, they got to the point going up that stack where the cheap mostly coal power from the western part of PJM no longer could [152] get across the wires to the eastern part of the grid because there was—they would have maxed out the ability for—maxed out what's called a transfer limitations on those wires.

No more, you know, the traffic example would be if you had another lane of traffic for the traffic to travel in, you could bring more, but now you've got all four lanes full and you can't put any more cars there.

So in those zones, then, they had to go up the stack after $16.46 to more expensive generator units or demand response within those zones before they got enough to that serve the load and clear.

And that's—and so what this shows is how that worked in each of those planning years.

BY MR. ERWIN:

Q. Now, you mentioned some folks that bid zero, are those called pricetakers?

A. Yes.

Q. Now, can any generator be a pricetaker and bid zero in the BRA?

A. Most can, but not everybody.

Q. Well, when you say most can, who cannot?

A. Well, the only ones that cannot are new—under the current Minimum Offer Price rule, would be a new gas-fired generator.

Q. So when—I stay away from separating, just when the RTO [153] clears at a particular price—

A. Yes.

Q. —let's go to 12/13 and the RTO put it at 16.46?

A. Yes.

Q. That 16.46 is the bids by who?

A. They're by the generators.

Q. But does it include the zero bids?

A. Absolutely. That tells you that there are an awful lot of zero bids in that zone.

Q. But the actual $16 is what was bid by?

A. Somebody.

Q. Combined cycle gas, et cetera?

A. It was bid by whatever, yeah, nuclear, coal, gas, anybody.

Q. Well, does nuclear bid, or do they bid zero?

A. They are allowed to bid zero.

Q. Coal?

A. Yes.

Q. Can bid zero?

A. It can. A gas plant can bid zero if it's cleared before.

But a new, a brand spanking new gas plant cannot. It has to bid, that's what this whole Minimum Offer Price rule is about, and that is how the rule got changed back in 2011 to thwart new entry. But under the 2011 version of the minimum price rule, a new gas plant has to bid at its actual cost or to the artificially set cost based on a formula that's contained in [154] the PJM tariff that I can explain, if you want.

But it's an administratively derived formula.

So the default is that you bid—that you have to bid at least this administrative number, which is called 90 percent of NetCONE, or the cost of new entry.

You have the ability to go to the market monitor to PJM and try to prove that your actual costs are lower, and if you can convince them, then you can bid at your actual price.

But you cannot bid zero.

Now, once you've cleared once, you can bid zero after that.

Q. Now, when PJM and the market monitor evaluating the bid for a brand new gas-fired, et cetera, did they apply something called the MOPR or Minimum Offer Price Rule?

A. The Minimum Offer Price Rule is the rule that establishes that whole construct I just described.

Q. And if you bid below the MOPR, they change your bid up to whatever the MOPR level was?

A. Correct.

Q. Is that correct?

A. Yes.

Q. So they change your bid for you?

A. The tariff requires them to change your bid for you, yes.

Q. Okay.

A. And if you don't clear that bid, then you don't clear.

[155] Q. And the MOPR, benchmark, if you will, is something called Cost Of New Entry, or CONE?

A. The MOPR floor is 90 percent of the cost of new entry, yes.

Q. And the Cost Of New Entry, is that an actual plant someplace?

A. No, that's—that is an assumed set of costs for a new combined cycle gas plant. That has no connection to reality.

Q. Okay. It may be higher or may be lower than reality, that's just what they decided to set it at?

A. I believe it is generally higher than reality, but it is a made-up number.

Q. Okay.

THE COURT: All right. Mr. Nazarian, I hate to be utilizing you as a great tutor, but I think you're doing fine.

THE WITNESS: I'm pleased to help however I can, Your Honor.

THE COURT: Let's just look at the 2012/2013 numbers just to have some numbers to look at.

THE WITNESS: Okay.

THE COURT: A coal plant has bid in at zero.

THE WITNESS: Yes.

THE COURT: Now, when they bid in at zero, do they say we commit capacity zero anywhere in the RTO, or do they say we commit in these zones?

THE WITNESS: No. You bid into the RTO as a whole, [156] but there's a limit to where your electricity can be transmitted.

THE COURT: I see.

THE WITNESS: So if you are located in a zone where there's a lot of capacity, right, so in western PJM, you bid at zero, but you're bidding at zero with a whole lot of local other plants, if you had that exact same plant that's in a tightly constrained area, I mean, just the most stark example is if you look at that blow-up on the far right there, that ATSI zone, the difference between the blue and the yellow there is $136 to $357, right?

You could go, you know, a mile on either side of that boundary and have the exact same coal plant, the price is going to differ.

When you bid, you bid to be a capacity resource based on where you are, and the clearing price is going to correspond to the zone where you're located.

THE COURT: All right. Let's look at the numbers we have here, because we've got the coal plant that's bid in at zero. We've got some other plant bid in at a hundred. We got some other plant that's bid in 133.37

THE WITNESS: Correct.

THE COURT: Somebody else bid at 139.73?

THE WITNESS: Right.

THE COURT: So but the price, the clearing price, is [157] set by zones; isn't it?

THE WITNESS: Yes.

THE COURT: Okay.

THE WITNESS: So if you are—if you—let's say you are a gas plant and your bid is $100, a nice round number, right?

THE COURT: Right.

THE WITNESS: If your gas plant is located in Ohio, and you bid a hundred dollars, during the 12/13 capacity auction, you will not clear.

THE COURT: Right.

THE WITNESS: Because there is enough lower cost generation around you that either bid zero or bid some $15.46 or lower, that you would be a lonely gas plant in Ohio, and would not clear.

That same gas plant that's located in MAAC or EMAAC that bids at $100, clears and gets paid either 133.33 in MAAC or 139.73 in EMAAC, because there was more expensive generation around them needed to fulfill the capacity requirement in that constrained area.

THE COURT: Let's just see this, a zone is in Ohio, and in Ohio, you have a projected need for that zone. How big is the zone, a half a state?

THE WITNESS: Some of them are bigger than others, but yes.

[158] And RTO zone can be all of PJM or whatever of PJM doesn't separate. So that one's malleable. But I mean the middle graph gives you—

MR. ERWIN: You're referring to the map?

THE WITNESS: I'm sorry, the middle of your maps.

THE COURT: You're sitting there in RTO land, whatever it is, and PJM says that the demand is so much?

THE WITNESS: Right.

THE COURT: And we look at the bids, and there's a zero and et cetera, and we can fill that need, if we take the $16.46 guys to fill up the stack, that's the clearing price for that area?

THE WITNESS: Correct.

THE COURT: Okay. Now, we're going to look at the zone which is part of MAAC?

THE WITNESS: Yes.

THE COURT: And MAAC says, okay, the problem with MAAC is that, number one, a lot of the zero bids and low bids can't get to MAAC in any event?

THE WITNESS: Correct. They're too far away, and the wires won't carry it.

THE COURT: So what you've done is you've taken off the bottom feeders in order to get to the RTO general area. Now, you're looking at what's in MAAC, and MAAC says, yeah, we can take some of that $ dollar stuff, but all of this, I mean, [159] the reason you can take it is, one, it's the price is $100, and two, you can get it there?

THE WITNESS: Right.

THE COURT: But the seller—what the supplier is doing is I assume they're getting paid, they're getting paid for their capacity, which is just inputted into the system?

THE WITNESS: Correct.

THE COURT: So you have a different look at a zone that is in MAAC, and that look is at a different stack, and that stack may have nobody at zero and nobody at 16.46, but it will have enough that $133 then, you can satisfy that need?

THE WITNESS: Right. The stacks separate essentially at some point along the way, yes.

THE COURT: And EMAAC, you're looking at almost the same stack as before, but presumably some of that stack's been eaten up by $133.37 stuff?

THE WITNESS: Yes.

THE COURT: So PJM is doing it kind of in a sequence of sorts?

THE WITNESS: It is exactly a sequence, Your Honor. You go until—you go successively through each next expensive unit until you get to a point where there's a limit to the degree where you can't move the next cheapest one into the zone that needs it.

So just again to look at that one in the middle, the [160] folks in New Jersey and on the Eastern Shore in that middle blow-up, right, for a while, they can get electricity from anywhere, but at some point the amount that can be transmitted runs into the—runs in the transfer limit.

And so then the next step up the stack for them has to be something from MAAC, because that's close enough, and you can still get the transmission to get it there.

And then after a while, you run out of that transfer limitation, and so you have to take the next unit up the stack from something even more local, and

so on and so on, until you get to the point where you've covered all of your need.

THE COURT: Well, and again, if I'm just asking you something that is too detailed to worry about, then we'll just turn it off.

But at this point, we have EMAAC and SWMAAC, which I understand is the same as the purple MAAC?

THE WITNESS: They're subsets, but yes.

THE COURT: They're subsets, and they have a stack of bids to look at, PJM, are they going to favor one group over the other?

THE WITNESS: They—no, they don't favor it. It's purely driven by location and transmission capability.

THE COURT: Well, MAAC and EMAAC—SWMAAC and EMAAC, there's a group of bids that each one can take to meet their needs?

[161] THE WITNESS: Yes.

THE COURT: And if you gave first dibs to EMAAC, then they would be able to come in lower than Southwest?

THE WITNESS: The dibs are driven by the transmission capability. It's all location. It's location and transmission wires.

THE COURT: All right.

THE WITNESS: So there's no favoritism. It's all just a matter of what is needed where and what you can get to where.

So what ends up happening is, just again to stick with the 12/13 year, MAAC as a whole sat outside the part of the grid where the $16 electricity could go over the wires. It was too far away. So they had to satisfy

their capacity. They had to go to the more local, more expensive units.

In the rest of the RTO, the more expensive units weren't needed to cover the capacity need because they had enough cheaper ones there, and they didn't have to go from outside.

Because there was a limit to the amount of transmission, and PJM is all about transmission and markets, right? They don't decide what power plants are needed where. They don't do policy. They don't decide any of that stuff. That's done differently.

They plan transmission, and they operate a [162] transmission system, and they operate these markets. So for them, it's all going to be driven by what juice can move over what wires and where.

THE COURT: One more question, if I can?

THE WITNESS: Of course.

THE COURT: So when PJM is looking at the price depicted for this clearing, they are looking at what the supplier has bid, plus the transmission costs?

THE WITNESS: No, sir. They're just looking at the bid. The transmission costs get factored into prices in a totally different way.

THE COURT: So it's binary, and that is they look at the bid and either you can or you can't get it?

THE WITNESS: Correct.

THE COURT: All right.

THE WITNESS: Then they move to the next one, and they look at the next bid. So if you know if you had the two bids that were a penny apart, then you move

up a penny. If you have two bids that are a hundred dollars apart, you jump up a hundred.

From the supplier's standpoint, they're trying to figure out what to bid based on their needs. Again, like a coal plant or nuclear plant that wants to run all the time because their costs are sunk, the economics of those are they want to bid low, because they want to get taken and get paid [163] all the time.

A plant, what's called a peaking plant, all right, is usually nowadays mostly a gas plant that's designed, can turn itself on and off very quickly, and it's designed to come on in bursts.

It may not want to get taken as a capacity resource, because it might cost a lot to turn it on quickly like that, doesn't want to run a lot necessarily. It may decide that it doesn't want to be taken as a capacity resource unless the price is $200.

So they're going to bid at the number that makes sense for them, based on where they are in their economics. What I suspect happens in a lot of the world is, you know each company looks at where they are. They look at the prices that have cleared in the past. They look at their costs, and they try to sharpen their pencil and hit the sweet spot and figure out for the highest price they can bid and still clear.

And so I mean the different players are going to have different motivations and are going to put themselves into the process, you know, into the auction at different prices.

THE COURT: All right. When you say the coal supply, coal powered supplier wants to get taken, they're going to bid at zero so that they're now committed. They got their $16. They would have been

happy to get zero. But when the time comes to produce energy, PJM's going to call on them—

[164] THE WITNESS: Correct.

THE COURT:—first?

THE WITNESS: Yes.

THE COURT: At least in the first category, because they're going to be—

THE WITNESS: Well, no. When PJM calls on them, it's going to have nothing to that do with the price they bid in the capacity auction. It's going to have all to do with what PJM needs where and when.

Now, as a practical matter, if you're a baseload coal plant or nuclear plant, I mean there's a certain amount of electricity that's needed all the time, 24/7, right?

So odds are PJM's going to call you for those needs, because that need is always going to be there.

It's when—but then when, you know, the people wake up in the morning, in the summer, when it starts to warm up a little bit, and the demand starts to go up a little bit, PJM is going to call on different generators that are capacity resources. It's going to call on them not with regard to what their bid price was, but it's going to call on them based on where they are and what PJM needs.

THE COURT: Well, what it is, it's going to call on the capacity successful bidders first before they go outside the capacity bid?

THE WITNESS: That much is true, yes. But then in [165] the energy market, like you can bid to participate in the energy market at a certain energy

price, and PJM will pick the cheapest of those in the zone,

So there's a—that's where the whole energy market construct kicks in.

If you are a cleared capacity resource, you're right, Your Honor, you're in the pile that's available for them to turn on whenever they need it.

What they're not going to do is say okay, you bid zero, you bid one dollar, we're turning the zero one on first. They're going to say all you capacity resources are getting paid your capacity clearing price regardless.

Now, we're going to look at the energy market and the energy need, and we're going to take the cheapest energy resource, which may be a function of location and fuel and all kinds of other things that have nothing to do with whatever their bid was in the capacity market.

THE COURT: So how does the zero bid in the capacity market make it more likely that that producer is going to be selling their electricity?

THE WITNESS: Well, for one thing, it makes—what they really care about in the capacity auction is they're going to clear, so they're going to get paid the capacity revenue.

THE COURT: Right.

THE WITNESS: They're more likely to get called based [166] on who they are, and the kind of plant they are, not based on the fact they bid zero.

THE COURT: The bid for zero is to get the clearing price as a bonus?

THE WITNESS: Yes. And that actually, you know, you used the word, bonus that is actually kind of how it's really worked, because these plants were all in Maryland.

Every plant was built during the regulated days. So nobody took a big financial risk to build these plants. It was all done under the old system. The plants are still there.

Now, they've had to maintain themselves and do environmental upgrades and things like that, but the capacity money is really just—it's an anchored revenue stream. I mean, it's a revenue guarantee over the course of that planning year. So it's great for the bottom line.

In reality, it has increased prices in Maryland. And then we can go down the path of getting into whatever you want to talk about the theory of whether it's going to create incentives for new generation or not.

But from the existing generator's perspective, it's a great deal, because it means they're getting paid just to be there.

In Texas, if you're just there, you don't get a capacity payment. You have to get paid based on how often you run and deliver energy. And there are pluses and minuses to [167] both systems.

THE COURT: Thank you for the tutorial. Please.

BY MR. ERWIN:

Q. Thank you, Your Honor.

When—let me back up.

When did RPM and MOPR and these rules go into effect in PJM?

A. 2007.

Q. All right. Now, when PJM proposed this, did they have to get approval from FERC?

A. Yes.

Q. And when they applied to FERC, what, if anything, did the Maryland Public Service Commission do?

A. Well, it was approved by the FERC before my time, so I'm not sure. I believe—so—RPM was a negotiated construct. And in fact our colleague and friend Larry Brunner was an administrative law judge at FERC, who was assigned to oversee the negotiations of RPM.

So the Maryland Public Service Commission, I believe, was one of the parties that was in negotiation. And if memory serves, we—I don't think we signed the RPM settlement doc, we just didn't oppose it. But I can't specifically—

Q. What were the terms of the settlement as in regards to state-sponsored new generation and application of the MOPR?

A. So one of the components of RPM as it was originally [168] approved, Your Honor, was a provision that said if there is a plant that is ordered by a state utility commission after an evidentiary hearing and a finding that there was a reliability need, that plant was exempt from the Minimum Offer Price ruling, it could bid zero its first year.

THE COURT: All right. Hold on a second. Okay. At 3:30, the Court Reporter will change, I think you can fully appreciate that.

MR. ERWIN: Absolutely.

THE COURT: Mr. Thompson, you're going to have a substitute available?

THE CLERK: Yes, sir.

THE COURT: Okay.

THE CLERK: We're ready when you are.

THE COURT: All right.

(Recess.)

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 5, 2013

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[2] PROCEEDINGS

(Afternoon session 3:38 p.m.)

MR. ERWIN: Thank you, Your Honor.

DIRECT EXAMINATION (cont'd)

BY MR. ERWIN:

Q Chairman Nazarian, going to just before the break, did FERC approve the settlement under which state sponsored projects were exempt from the MOPR and could have been zero?

A Yes.

Q All right. Now, when Maryland and New Jersey began their projects under the Maryland RFP and

what's been called the New Jersey LCAPP, what if anything did the generators and PJM do?

A They sued, filed a complaint at the FERC to change the rules.

Q All right. And when they went to FERC to change the rules, that was with regard to the MOPR?

A Yes. In February 2011, I think on the 4th.

Q What, if anything, did the Maryland Public Service Commission do?

A We opposed the proposal at FERC.

Q Okay. And what did FERC decide?

A Well, the FERC ended up more or less adopting a different proposal than the one—so Your Honor, what happened is that a group called the P3 group, which is a group of generator companies, that I believe includes Mr. Meyer's clients, filed a

* * * *

[5] Q And what's the status of that appeal?

A The appeal's pending in the United States Court of Appeals for the 3rd Circuit.

Q Okay. And Maryland is a party in that appeal?

A Yes.

Q All right. When was the last new generation in Southwest MAAC to become operational?

A I think in 1992. Now, if you—I guess it depends on whether you want to count the Gould Street plant being unmoth balled and retrofitted as a new plant, which I don't. But if you did, that one is around 2009. But before that it's the 90s.

Q Okay. Now, let me sort of ask you to summarize what we've been discussing for the last hour. Could you please describe the respective roles of PJM and the Maryland Public Service Commission with regard to reliability?

A With regard to supply reliability?

Q Yes.

A PJM's job, as we discussed before, Your Honor, is to run markets and to run a transmission system. It's been the role of state utility commissions, for as long as there have been state utility commissions, to ensure that there is an adequate supply of electricity in their respective states. In 26 of the 50 states they're still in the old regulated paradigm. And the state commissions perform what was always called here [6] integrated resource planning. They plan over time for what needs there are and how best to meet them. And state commissions make the policy decisions about whether new plants are needed, whether old plants should be retired, or how to calibrate the fuel mix, all of those things. And there are states within PJM, as I mentioned before, Virginia and West Virginia among them, that still operate that way. So it's not consistent at all with the concept of markets or RTOs. Now the fact that Maryland and 23 other states have restructured, and D.C. too, is not inconsistent with the notion that it's still the state's utility commission's role to ensure a reliable supply of electricity. And, in fact, the Federal Power Act specifically contemplates that. And the original—the original RPM settlement specifically included the provision that we talked about before, that allowed states to order new plants, based on reliability findings, and those plants could bid in at zero.

MR. MEYER: Your Honor, I—interject that last answer sounded to me an awful lot like a discussion of what the Federal Power Act contemplates. And I'm not—I'm not inclined to insist that he not be allowed to testify to this, but only insofar as our witnesses aren't foreclosed from speaking in the same terms.

THE COURT: Well, I just took him to say what was provided, the same sense that he's quoting something.

[7] MR. MEYER: Very well.

THE COURT: I mean, that's—I'm not—I don't want to open this up into having miniarguments about the legal issues.

MR. MEYER: I agree with that, Your Honor. I just want to make sure that we understand that there are symmetrical standards being applied to both sides' witnesses.

THE COURT: All right. Well, I'm trying to draw a line between opinion and simply reporting that a statute says this. Or if it's really not debatable, it does this. Go ahead, Mr. Erwin.

Q (BY MR. ERWIN) Were you done, Chairman Nazarian?

A Yeah, I guess just in response to the colloquy, Your Honor, I would just say I'm only speaking structurally, when you're talking about dividing who's in charge of what. And I'm not trying to make a legal argument. But as a regulator we understood—I understood my job, and we understood our job to ensure a reliable supply of electricity in our state. And we watched our counterparts in other states do exactly the same thing. And you don't have to go very far to see that happening right now.

And it just means we have different—in restructuring we have different tools. We have tools, we still have responsibility over the demand side, the demand response programs, those are our—those are policies we run. We have [8] this residual state law authority to order generation. We have different tools than our counterparts in integrated states still have. But it doesn't mean that we're cut out of that business.

Q Okay. Thank you. I want to shift topics now, Chairman Nazarian to the recent history before the Maryland Commission, leading up to the April 12th order in 9214.

A Okay.

Q Let me start by asking you what are summer reliability conferences with regard to the Maryland Public Service Commission?

A Summer reliability conference is a conference to which we invited—we invited PJM, because we can't order them to do anything. We directed the local electric companies to appear every year. In the latter part of May, the first part of June. So before the summer really got going. And the purpose of that conference is to make sure everybody is ready for the summer. We do one in the fall, latter part of the fall with the gas companies before things get cold in the winter, and make sure everybody's ready for the winter.

Q All right. And did you do one in 2007?

A We did.

Q Let me refer you to Defendant's 241, it's tab 1 in your book. Tab 1 of 241.

A Okay.

* * * *

[53] from making business decisions in a competitive market. What I can't understand is why a generator whose costs were $120 would bid $200, and take the risk of not clearing at $120.

Q Okay.

A Or $125 or $130.

Q So the question I was asking you—

THE COURT: Mr. Nazarian, if I could, referring to costs here, this is the cost that—of being committed.

THE WITNESS: Well, so here's one of the places where the theory of RPM diverges from reality a little bit. The theory of RPM is that your capacity price bid is supposed to reflect your cost, your fixed cost, your sunk cost of being there, right.

THE COURT: Your overhead.

THE WITNESS: Essentially your overhead, right. And the reason that that's the case is because it's all built around this notion that the net cost of new entry is the tipping point that tells you whether new generation is needed or not. If the clearing—the price clears above the net cost of new entry, according to the theory of RPM, the market price is telling you that it's now economically rational for a new plant to come in, because the clearing price is higher than that cost of that new plant. Now that's baloney because it's only a one-year signal, and it's unreliable and it's useless. But that's the theory.

[54] What should happen to follow that theory then is that every plant who bids in should be bidding at what their cost is. Now, in reality you're not required to do that, unless you are a brand new gas

plant. If you're not—if you're anything other than a brand new gas plant, you can bid into the RPM auction at whatever price you want. It's supposed to reflect your cost, but nobody's enforcing that. And the rules don't require it. So that's what when we talked about this behavior of bidding at zero, that's how generators who would rather be taken, who would rather clear than not, will bid at zero because they figure somebody else will set the marginal cost, and they're better off getting taken. And that's how you have an RTO clearing price of $16 ever happen.

THE COURT: Well, this is a very helpful tutorial, because it's at the right levels. But let me—so let me ask you this. You've got a generator, and the generator's overhead, that is the cost of keeping it in existence for a year is a million dollars.

THE WITNESS: Okay.

THE COURT: And so if I bid in the capacity market, I bid $100—$100 which transfers to the million dollars total.

THE WITNESS: Okay.

THE COURT: Just say so that I'll have my overhead covered, and I'd like to clear, et cetera. Remembering that if [55] I don't get cleared, I haven't sold capacity, but I can still sell it to the market.

THE WITNESS: Yes.

THE COURT: And I'm getting the same money whether I sold my capacity or not for what I sell, correct?

THE WITNESS: On the energy side, yes.

THE COURT: Yes, that's right.

THE WITNESS: But you'll get zero for capacity if you don't clear.

THE COURT: But the question then is, I have a million dollars of fixed costs that the capacity clearing price is going to pay me for. Why would anybody—why should I bid $200? Which is, let's say, a high number—in other words, why should I not bid low enough to at least get something against my overhead, because if I—it's all gravy, so to speak.

THE WITNESS: Yes.

THE COURT: I'm not following this—a little bit of this strategy we're talking about, in that everybody who clears gets a tremendous payment, a great pay. So, I mean—

MR. MEYER: Your Honor, if I may explore?

THE COURT: The game is, I mean, why are you going to worry about—I mean, I think the game is to try and figure out how to get something from the capacity market to maybe hope that it clears at a high enough number. But the fact that your [56] costs are $200. And you figure everybody else is going to be bidding lower. So you bid $100 because you would get at least half your overhead.

THE WITNESS: Well, that's exactly right, Your Honor, and that's a rational business decision a rational business person could make. But the Minimum Offer Price Rule artificially prevents that. And the reason it does that is because the rules are being rigged to thwart new entry. The people who have the existing plants, who are allowed to bid at zero --

THE COURT: Right.

THE WITNESS:—and who would like the clearing price to be higher because supply is tighter,

they would like new power plants to be kept out. And so a way you keep new power plants out is you make it so that they have to—they are artificially required to bid a higher price into the auction in order to clear.

Now, the current version, the Minimum Offer Price Rule says that for a new gas plant, you have to bid your cost, which is assumed to be 90 percent of this artificial cost of new entry, unless you can convince PJM and the market monitor that your actual costs are lower. The version of the Minimum Offer Price Rule that PJM is pushing now at FERC, would push that to 100 percent. And would say that instead of having to clear once before you can go to bid zero, like every existing [57] generator, you would have to clear three times.

So the reason that you have this MOPR floor is to artificially constrain new entry. Or at the very least to ensure that if new plants come in, they push the clearing price up when they do. And they prevent rational business people from making exactly the calculation you just made on the bench there, Your Honor.

THE COURT: So let's get this straight. First of all, if everybody bids zero, nobody would get anything.

THE WITNESS: Right.

THE COURT: But we have this thing is that we're going to have this stack. So all the good old boys bid zero, one new guy comes in, he's required to bid at $100. He's way at the top of the stack, and now everybody gets dragged up to $100.

THE WITNESS: If he clears.

THE COURT: If he clears. Because 99 percent of the capacity is reached before they get to him. He's at

the very top. Once they reach him, everybody gets to $100.

THE WITNESS: Right. But if he misses—

THE COURT: If he misses everybody gets nothing.

THE WITNESS: Well or no, they get—literally everybody else bids zero then yes, you're right. But the reality is there are a bunch of—I don't really. Know, but I assume just from observing some auctions where the clearing [58] price has been $16 and $27, that there are a lot of players within the RTO that bid either at zero or very low.

The cost of new entry calculation yielded a MOPR level, in this 15/16 auction, that was $168 or $169. So the cost of new entry is not quite pushing $200 in the last auction. I don't know what it is in the upcoming auction. But it's in that range. So the idea is, you shouldn't be able to clear, as a new entrant, unless you are pushing the clearing price up to that level or above.

But that's—it artificially forces that bidding behavior only, and only on the part of the new participant. It lets the existing participants, none of whom in Maryland built their plant in this paradigm, by the way, it lets them bid zero and free ride off the auction.

And you're right, if everybody did that, then at some point maybe the auction bids—clears at an artificially low level. But if this is supposed to be a market, if it's supposed to be a competitive market, which it's not, it's a construct, then people should be allowed to make rational business decisions. And these rules discriminate against new entry for the

purpose of pushing that price artificially upward. Now, we've made that argument at FERC, and it's fallen on deaf ears. But that's the reality of it.

THE COURT: If the beneficiary is the industry, if we're going to look at this sarcastically and say that PJM is

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, *ET AL.*

Plaintiffs

v.

DOUGLAS NAZARIAN, *ET AL.*

Defendants

March 6, 2013

DAY THREE BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F Eisenstat, Esquire
Daniel A. Broderick, Esquire

Reported By:

Jacqueline Sovich, RPR, CMR, FOCRR
Official Court Reporter

[2] PROCEEDINGS

THE COURT: Let's proceed, Mr. Meyer.

MR. MCPHERSON: Your Honor, plaintiffs call William Massey.

THE COURT: Mr. Massey is from Washington?

THE WITNESS: Yes, I am.

THE COURT: If we can get him out so he's able to get home, it would be nice.

THE WITNESS: Thank you, Judge.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. First order of business is if you would adjust that microphone to yourself, right where that is, state your name then spell your name for the record.

THE WITNESS: My name is William L. Massey, William WILLIAM, L as in Lloyd, Massey, MASSEY.

THE CLERK: Thank you.

DIRECT EXAMINATION

BY MR. MCPHERSON:

Q. Good morning, Mr. Massey.

A. Good morning.

Q. Mr. Massey, what do you do for a living?

A. I'm a partner at Covington Burley, a law firm in Washington, D.C.

[3] Q. And what are your responsibilities there?

A. I have the energy regulatory practice.

Q. What does that mean? What do you do as the head of the energy practice?

A. I supervise associates' work with other partners and counsel, organize the practice. It's focused on FERC and state regulatory issues.

I represent an array of clients, utilities, private equity funds, transmission owners, customers, and others that participate in electricity and natural gas markets.

Q. Could you describe briefly in very general terms the matters on which you work for these clients?

A. Sure. Most of it relates to issues before the Federal Energy Regulatory Commission, FERC. I have advised clients on a wide array of FERC issues, involving competitive markets, tariffs, market power, market-based rates.

I've handled a fair number of FERC enforcement matters brought by FERC Office of Enforcement against market participants that are accused of violating the rules.

Q. And do you do any work outside of Covington and Burley?

A. I'm an adjunct Professor at the Georgetown University Law Center, and have been in that position for about six years. I teach a course entitled Energy Training and Market Regulation, which is basically a course about FERC policy with respect to electricity and natural gas markets.

[4] Q. Thank you.

Could you just briefly describe your educational background?

A. I have a juris doctorate from the University of Arkansas School of Law, and an LLM from the Georgetown University Law Center.

Q. After you received your law degrees, what was your first job?

A. Well, my first law degree was in 1973. My second law degree was in 1985. I practiced law in Little Rock for a while. I was a law clerk for the Honorable Richard S. Arnold of the 8th Circuit Court of Appeals, who is a dear friend, now deceased, I'm sorry to say.

I left his employ in 1980 to become Chief Counsel and Legislative Director for Senator Dale Bumpers of Arkansas, a democrat who was a key member of the Senate Energy Committee, and I handled his entire legislative agenda for him and focused a good deal of my time on energy issues before the committee.

I was a partner at the Mayer Brown and Platt law firm after I left Senator Bumper's office. I represented a wide variety of clients. I represented some clients in debates that led to the enactment of the Energy Policy Act of 1992.

In 1993, I was nominated by President Clinton to serve as a member of the Federal Energy Regulatory

Commission, and I served as a Commissioner for 10 and a half years from [5] 1993 until 2003.

Q. What were your responsibilities as Commissioner at FERC?

A. Well, the Commission regulates wholesale electricity markets, transmission of electric energy and interstate commerce. It regulates natural gas markets, regulates oil pipelines, hydroelectric facilities.

During my term at FERC, we were initiating this movement to wholesale competitive markets, and during my time at FERC, I probably spent anywhere from half to two-thirds, three-fourths, maybe sometimes higher, of my time on electricity market questions.

Q. Can you describe some of the policies that you developed and implemented as a Commissioner at FERC?

MR. EISENSTAT: Objection, Your Honor.

THE COURT: Well, let's put it this way, there's no question about Mr. Massey's qualifications, so if it's about his qualifications, it's unnecessary. It's giving Mr. Eisenstat heartburn. I'll sustain the objection only because

MR. EISENSTAT: I stipulate to his qualifications being a former FERC Commissioner and—

THE COURT: Qualifications are certainly well-accepted.

MR. MCPHERSON: That's fine, and if that's the case, then we'll move right along, and plaintiffs will tender Mr. Massey as an expert in FERC policy regarding wholesale

* * * *

[30] that, and I don't plan to ask him that.

THE COURT: This is what, as he's explained, this is what this contract does, and what's your next question?

BY MR. MCPHERSON:

Q. My next question, Mr. Massey, is does it make any difference whether we view this pricing contract for differences as a contract that is for the physical delivery of energy and capacity?

MR. EISENSTAT: Objection.

A. Well, I cannot state.

MR. EISENSTAT: Objection. Difference, in what regard?

Q. As a matter of regulatory practice, what does it mean, you know, you've said that this is a contract for the physical delivery of energy, so I'm just asking as a matter of regulatory practice, what does that mean?

A. Well, as a matter of the physics of the system, a contract for physical delivery actually moves electric energy on grid. It affects the use of the grid. It affects the distribution system. It affects any electric energy that actually moves, affects the usage of the grid, congestion. It affects prices on the grid in wholesale markets.

So the fact that it requires these physical market activities actually has an impact on how the system as a whole operates, which is distinct from a simple bet on prices.

[31] MR. EISENSTAT: Excuse me, Judge.

THE COURT: Okay.

MR. EISENSTAT: Judge, just for the record, I'll please refer you to paragraph 45 where this issue was struck. (Pause.)

THE COURT: I'm just going to look at paragraph 45 and see which exhibit is that behind, where is that?

MR. MCPHERSON: He's referring, Your Honor, to P 595, which is in your binder.

And while you're looking at paragraph 45, I'd urge Your Honor also to look at paragraph 40, which does not strike what Mr. Massey just said in contrasting the CPV pricing contract for differences to a financial agreement.

MR. EISENSTAT: Judge, with all due respect, if you look at the entirety of that connection beginning on paragraph 38, and indeed the heading beforehand, it's clear that what was struck in the topics that were struck, and one of them certainly had to do with whether or not there was any physical delivery required or whether the provisions constituted physical delivery to the EDCs.

THE COURT: Let me see if I can't help us focus here. The sentence is—a certain sentence is struck, but it's really part of a sentence.

Mr. Massey has testified to the contracts provide for physical sales, they do. The contracts provide for payments to [32] CPV in connection with those sales, well, it does, at least he's pointed out.

What I would strike is this is the test for FERC jurisdiction, because that's for counsel to argue what is the test for FERC jurisdiction.

Let me try and say that at least as I understand some of the things, where you're going is that we have the CfD contract that's at issue that has the

characteristics that Mr. Massey described, and that is there is a document, which provides for this fixed price payment against—rather than a variable receipt and in the same document expressly and necessarily requires participation in the physical market, providing capacity, et cetera.

A provision, which at least according to Mr. Nazarian, and who can doubt it, that the one thing that the PSC wanted to do, a thing, was to ensure that this order was going to result in bricks and mortar construction in, when I say Maryland, I mean the SWMAAC, and not some financial arrangement, for which, so that—okay. We have that.

We also have, as illustrative of transactions, contracts, that in and of themselves are standing alone don't expressly require sales of electric energy like this, sales capacity like this.

But are certain—except in the rare case, and I suspect I may hear from the experts, the rare case is going to [33] be rare indeed where some speculators just want to have a bet on the market. That typically, I surmise, I guess Mr. Massey can answer this, that typically, these pure financial contracts are entered into by people who want to have hedge protection, financing ability in order to be able to get a lender, et cetera?

So that implicitly, if not expressly, they're going to be tied to production, that nobody's going to enter into one of these things, at least on the supplying side, and simply make a bet.

I know that's your dispute. But I think that's where I am. So I guess, Mr. Massey, although you may not be the right guy to ask this, my impression is that the pure bet contract, the speculative contract,

without connection with anybody that's actually doing something on the market is pretty rare; is that accurate?

THE WITNESS: Your Honor, there are -- in these 700 and so market participants, there are banks, a lot of others that participate in, that participate, that enter into financial agreements, some of which are a bet or prices.

For every hedger, for every hedging contract or body of hedging contracts, there has to be sufficient speculators on the other side of those contracts to provide the needed liquidity to the marketplace.

It is true that market participants that have [34] physical contracts also want to hedge their physical contracts with financial agreements that are purely financial. But the purely financial agreement does not by its terms require performance of the physical contract. It just uses that contract to peg the fixed price against which the variable price will float.

THE COURT: I guess I think that's what I said, at least what I intended to say, and it's well-articulated, that the contract at issue has within its four corners express provisions that you have pointed out that require sales in the market.

THE WITNESS: Yes, Your Honor.

THE COURT: The typical hedge transaction, and maybe the typical contract of another, there are many other contracts in which there may be a speculator on one side, but the purpose of the contract is to affect somebody who's actually in the market and going to do something in the market.

And then we can argue about whether the fact that something is within the four corners of the

contract makes a difference for legal purposes from a contract that doesn't have it within the four corners but is implicitly there.

But I'm only saying I think that we're in the same boat. That in your experience, it would be very rare, if nonexistent, to find a CfD contract where neither side was really in the physical industry.

[35] THE WITNESS: Judge, I'm not saying it would be extremely rare. There are marketers and others in the markets that place bets on prices and provide that liquidity.

It is certainly true that one of the ways market participants use those financial agreements is to hedge their risk that arises from physical contracts.

But that quote "purely financial arrangement" certainly in its four corners doesn't require the physical delivery. In other words, the underlying physical contract is used to peg a price. But if the supplier or whatever contract it is, should default on that contract, not perform, the financial agreement continues, and is binding, regardless of performance of the underlying physical agreement.

That is not true with respect to the CPV contract.

THE COURT: All right. Well, let me try and get—see if we can agree on something, because I certainly want to. We've got the CfD deal, that has in its terms the things you pointed out, no doubt about it.

We then have what you would say are purely financial contracts. And that has—you don't find those things within the four corners.

Some of them, some of those, 90 percent, 10 percent, some of those purely financial contracts as a matter of reality are done with the certainty, near

certainty, understanding that there's going to be a physical transaction that is facilitated [36] by the existence of the hedge. Certainly—and some of them may be ones in which that's not true, and it's actually going to be even—there's going to be no physical transaction. That's all I want to say is we have—we have three categories of things, and I don't think that that's really in dispute, and the kind of dispute I think we're having among counsel is that does the existence of something within the four corners make it other than purely financial, which arguably puts it within FERC jurisdiction?

And or is it effectively the same as a contract that doesn't have it within the four corners but is pretty implicit that's going to happen, or a contract, and we've heard all about the Longview contract, in which you can look at the four corners of the contract arguably, and we can arguably tie it to a transaction.

And I guess to shorten it, I mean you would agree there's at least those three categories that I've said.

THE WITNESS: I do agree with that, Your Honor, and I think Your Honor's statement is a fair statement. I mean there's just a lot of varieties of these agreements.

THE COURT: All right. And I understand your view is—okay. And I guess you can ask your next question, counsel.

BY MR. MCPHERSON:

Q. Thank you, Your Honor.

I want to move beyond now the terms of the contract, [37] Mr. Massey, and talk about other aspects of the Public Service Commission's order, the April 12, 2012 order.

Does that order call for new generation anywhere within the PJM?

A. It does not.

Q. What does it call for?

A. It calls for the new combined cycle gas facility to be located in an area called SWMAAC.

Q. And I want you to please turn to plaintiffs' demonstrative 29 to help explain what you mean by that.

A. I have it before me, counsel.

Q. So if you could just explain what you mean by—well, explain what you mean by the market that you described Maryland PSC order calling for?

A. Well, the market was a market that was restricted to a physical location called SWMAAC, which is basically Maryland plus D.C., about 98 percent of SWMAAC geographically is within the State of Maryland.

Just for comparison purposes, the right-hand column is the geographic area of PJM's 13 states plus the District of Columbia. What's the geographic size? SWMAAC is about 10,000 square miles. The PJM Interconnection is about 214,000 square miles. So that's 21 times larger.

Generation technologies, the Maryland Public Service Commission specified natural gas-fired facility. PJM [38] Interconnection is a home for over a thousand quite diverse facilities; coal, nuclear, wind, hydropower, natural gas, and others.

What about new generators versus existing generators? No. In the Maryland case, existing generators are barred from participating in this

market, this RFP. Uprates are prohibited from participating. It's only new generators built after a certain date.

In PJM, it's all the above, all generators participate in the capacity and energy markets.

A number of generators in the Maryland case, there were three that were considered in PJM interconnection. There are well over a thousand generators. So that's just to provide some context about the scope of the PJM market versus the scope of the market for a sale from an independent generator that was created by the State of Maryland in its RFP.

MR. MCPHERSON: Thank you for that context, Mr. Massey. Nothing further.

THE COURT: Oh, okay. Mr. Eisenstat?

MR. EISENSTAT: Thank you, Judge.

Excuse me, Judge, could you just give me 30 seconds to read the witness's last answer, because the last couple questions and answers weren't really part of his report. So let me just see what he said.

* * * *

[83] THE COURT: Let him finish his sentence. Mr. Massey was in mid sentence there.

THE WITNESS: All right. I have already said that FERC constructs the markets that lead to certain price signals based upon market fundamentals.

And I can tell you from my time at FERC, those spot market fundamentals, how they are designed, whether they have an impact on long-term decisions are critically important to FERC, and in my judgment to market participants.

I cannot cite a particular generator that has moved forward. I believe they do move forward looking at all the price signals in the market and other factors and decide where and when to build new generation. Demand responders do exactly the same thing.

Q. Can you cite me to any FERC order that in any way, shape, or—excuse me.

Can you cite me to any FERC order that says that the capacity market of PJM is the exclusive means by which developers should determine whether it makes sense to build in PJM?

A. Why, of course not.

Q. Thank you.

I have a few questions about the FRR requirement. Do you believe that in this case the FRR option was a viable option?

[84] A. I believe the FRR option, which is part PJM tariff and approved by FERC is an option, that EDCs can take a look at working with their state commission.

I don't have economic data about its economic viability, but it's definitely an option, and that's why it's in the tariff.

Q. It's an option in theory, but—

A. I think AEP has used it before.

Q. But in this case, I know AEP has used it, but you have no appreciation as to how it would work in this particular case, with respect to Maryland, correct?

A. Oh. I know that the EDCs could, or an EDC could decide it wanted to pursue that option, work with the state commission. I would think an EDC

would want to make sure the State Commission is on board.

The EDC would then make an application to FERC to pursue this option, and that application would be approved or rejected by FERC.

There's certain requirements in the application process. For example, you'd have to stay out of the capacity market for at least five years. You've got to show to PJM that you will have the resources available to meet your load. But that process is available to market participants, and I'm aware based on memory that at least one significant market participant has used it in the past.

* * * *

[121] Q. And is it possible that filing could change the MOPR?

A. Well, the filing proposes to change the MOPR. What FERC's ultimate decision will be, I don't know.

Q. Okay. At some point, Mr. Eisenstat asked you whether the CPV pricing contract for differences require a particular bid amount for CPV's capacity.

Do you remember that?

A. Yes.

Q. And you said no, but you wanted to add something that you're not permitted to add?

A. Well, I can't remember now.

(Laughter)

Q. You lost your chance to be helpful, I guess?

A. I think hunger has overtaken me, Mr. McPherson.

Q. I'll help with a very easy question. Actually, not quite yet. I have just one other thing to cover first.

You were asked a number of questions about demand response?

A. Yes.

Q. And state subsidies and renewable portfolio standards and state regulations of that sort?

A. Yes.

Q. Do those affect FERC policy in the same way that CPV's pricing contract affects FERC policy?

MR. EISENSTAT: Objection.

[122] MR. MCPHERSON: Well, Your Honor, Mr. Massey was asked questions about this subject. I think it's only fair for him to provide his view on the subjects he was asked.

MR. EISENSTAT: I asked about effect on the market, Judge.

THE COURT: Well, can you do it in terms of the market instead of the policy?

MR. MCPHERSON: Sure.

BY MR. MCPHERSON:

Q. Does it affect the market differently than the pricing contract for difference might affect the market?

A. Well, the pricing contract for differences in my judgment is a contract for physical sales into the market, and that will definitely have an impact on the market. It moves electric energy. It will use the transmission system. So definitely it will have a rather direct impact on the market.

A number of state policies may have some—some impact on the marketplace, but this strikes—this strikes me as a very direct impact on the marketplace.

Q. You were asked whether you could cite a FERC order concerning demand response. Can you turn to plaintiffs' exhibit 350, which is in your binder?

A. I'm sorry, I don't see it yet. Is it toward the back or in the front?

Q. It is the second tab.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

v.

DOUGLAS R.M. NAZARIAN, *ET AL.*,

Defendant.

March 6th, 2013

THE ABOVE-ENTITLED CASE CAME ON FOR A BENCH TRIAL BEFORE THE HONORABLE MARVIN J. GARBIS, UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:38 p.m.)

MR. PLUNKETT: Your Honor, plaintiffs call Richard Wodyka.

THE COURT: Very good.

THE CLERK: Raise your right hand. RICHARD A. WODYKA, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself. State your name and then spell your name for the record.

THE WITNESS: Yes, my name is Richard, middle initial A Wodyka, W o d y k a.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. PLUNKETT:

Q Mr. Wodyka, in what profession do you work?

A I work in the electric power industry, focusing on power system operations and planning.

Q And how long have you worked in that industry?

A I've worked in the electric power industry for over 40 years.

Q Can you describe your educational background?

[3] A Yes, I have a bachelor of science in electrical engineering from Villanova University in 1972. I have a masters of systems engineering from the University of Pennsylvania in 1978.

Q I want to talk a little bit about your professional experience. But first let me ask you if you have prepared reports in this case?

A Yes, I prepared an opening report as well as a rebuttal report.

Q Can you tell me if your opening report is found in your binder at Plaintiff's Exhibit 584?

A I think I remembered to bring my glasses up. Correct.

Q That is your opening report?

A That is correct.

Q And can you confirm that your supplemental report is at Plaintiff's Exhibit 494 in your binder?

A Yes, it is.

Q All right. Can you sketch out briefly the jobs that you had at PJM. I believe you were there for about 32 years; is that right?

A Correct. My career at PJM was over a 32-year period.

Q Can you describe that for us?

A Sure. Generally my career at PJM I break into three categories. Approximately the first ten years of my career I was an electrical engineer doing electrical engineering duties, [4] supporting the system operations and planning functions at PJM. The second ten years of my career I was a senior project manager as well as a department manager of two different departments, doing again, supporting systems operation and planning activities. And the last 10 to 12 years of my career I was an executive at PJM, again, with responsibilities for as PJM has

transforming itself from a tight power pool organization to the RTO it is today, I had a leadership role in doing various activities across that time frame.

Q Let's talk a little bit more about second category you mentioned when you were involved in system planning. I think that might be most relevant to the work you've done in this case?

A Correct.

Q Can you provide a little more detail about what your position was and what you did?

A Sure. One of my managerial positions at PJM was manager of system planning. Approximately 8 to 10 engineers reported to me. We did the kinds of analysis on resource adequacy that's still done by PJM today as far as developing installed capacity requirement and installed reserve margin, if you will, under today's nomenclature. And then we did regional reliability studies evaluating how the system was operating, as well as doing coordinated studies with our neighboring systems, again, to coordinate operations and planning across the [5] boundaries of PJM.

Q You mentioned in your third phase you were an executive and that you had some role in the transformation of PJM to an RTO; is that right?

A That's correct.

Q Can you describe that a bit more?

A Sure. One of my first executive positions was vice president of system coordination. And in that role I had the responsibility of working with the transmission owners at the time to develop the regional transmission planning protocol that exists at PJM today. So we developed the philosophies, the

architecture. And basically the philosophy as it exists today now. Under today there's been a number of changes of timing and some of the other rules and regulations. But the fundamental philosophy that was developed I had a hand in that.

Similarly we were also developing a generation interconnection process that was developed as we were starting up PJM. And I had a direct role in that, working with the members of PJM at the time to develop the generation interconnection process, again, that exists at PJM today. The timing of, you know, when queues are formed and some of the other particulars have been modified over the years, but the fundamental philosophy of how generators get interconnected to the grid, as you know, was developed back when I was [6] responsible for those activities.

Q I know from your CV attached to your opening report that you became executive vice president and chief operating officer in 1999. Can you tell us a bit about what your responsibilities were in that position?

A Sure, in that particular role as an executive, I had the day-to-day responsibilities for managing PJM, both system operations, system planning, the computer technology activities. Pretty much all the activities that PJM runs except for legal, finance, and markets. Those three other functions were under vice presidents in other areas of PJM, but as the chief of staff for the organization I coordinated activities with those other departments and divisions of PJM at that time.

Q And your final position at PJM was senior VP regional transmission organization. Do I have that right?

A That's correct.

Q Can you tell us a little bit about that?

A Sure. In that role, as I got moved from being the chief operating officer, at the time PJM was undergoing another series of transformations as far as expanding the geographic footprint of PJM. And in my role of working with neighboring systems who are interested in joining PJM, we—ded that I could not longer fulfill the role as the—managing the day-to-day operations of PJM. So they split up my [7] responsibilities and replaced me in that position. But my responsibilities as—was at that time then to negotiate, if you will, with the companies that had an interest of joining PJM. And part of that role was going to work with their legislators and state regulators of various states to educate them on what the benefits of their utilities joining PJM would be.

Q And in what year did you retire from PJM?

A I retired from PJM in May of 2004.

Q Tell us briefly your professional experience since your retirement, as it might relate to this case?

A Sure. Upon leaving PJM I had my own independent consulting firm for about a year, doing consulting activities in the electric power industries, supporting clients who were interested in learning how PJM was operating or dealing with some regulatory issue. I joined a small company called Gestalt and helped them build a company. And then I left there because it was acquired by a much larger company. And I decided I didn't want to join a large company. I preferred a smaller organization. And I, again, formed my own consulting outfit.

Under some of the work I do as a consultant, one of my activities is I'm the independent third party for if

North Carolina Transmission Planning Collaborative, which is responsible for practice is, again, expert testimony on various FERC or state PSC-type issues, dealing with various kinds of issues regarding system operations or transmission system planning.

MR. PLUNKETT: Your Honor, based upon Mr. Wodyka's education and experience, I would like to offer him as an expert in electric power systems planning and operations.

MR. KLEINMAN: No objection, Your Honor.

THE COURT: Okay. That's Fine.

Q (BY MR. PLUNKETT) Mr. Wodyka, have you come to court today prepared to offer your expert opinions in this case?

A Yes I have.

Q Can you describe, in general terms, the opinions you will offer?

A Yes. In general I'll discuss three subject matters. And

I'll offer an opinion on each. The first one I will discuss the role of PJM as it applies to resource planning and transmission system planning over the PJM footprint. And my opinion is that PJM has the necessary and appropriate process, procedures, and mechanisms in place that can ensure system reliability and resource adequacy across the PJM footprint, which includes Maryland as well as the SWMAAC region.

The second area I will discuss has to do with the results of their recent reliability studies, and how those results effect this case. It's my opinion that the

recent reliability study results that PJM has put forth indicate that

* * * *

[106] transfer. The transmission system, as I said earlier, is a good transmission, it's a good strong transmission, and this just identified that not all the capability's being used up.

Q (BY MR. PLUNKETT) And based on the information you have reviewed, do you have any reason to think that the transfer capability was different in 15/16 than it was in prior years?

A Generally, I would say that it would be the same type of analysis, you know, would show you the similar types of results, the numbers would change, but you know I would say there was still unused transfer capability in general.

Q Okay. Let's conclude our discussion of your second opinion' regarding the reliability situation, by having you conclude and tell us what your opinion is, based on your review of the information about whether or not the reliability situation in SWMAAC justified an order for new generation to be built?

A Yes, based upon all of my analysis, and my understanding of how the PJM process and mechanisms work, the results clearly indicate that there was no reliability issues in Maryland or SWMAAC that would have justified, you know, the Commission taking action to, you know, suggest that additional resources were required.

Q Okay. Let's move on to your last opinion regarding what I'll call the locational issue. And that is assuming contrary to what we've seen, that there was a reliability problem in [107] SWMAAC, was there

any justification for requiring that the problem be solved by building generation specifically in SWMAAC, what is your opinion on that subject?

A No. Based on my knowledge of the PJM system, and the review I did of all the results we just went through, it's clear to me that the locational requirement was not necessary. That there are generating resources throughout PJM, and PJM has operated on a single-system basis. The boundaries of MAAC or SWMAAC are not impediments to getting those resources, you know, to serve load in SWMAAC. So the locational requirement was not necessary.

Q Mr. Wodyka, do the borders of SWMAAC, which you can see on both of those maps up there, do they matter for purposes of locating a power plant if your concern is resource adequacy in SWMAAC?

A No. As I said, the corporate boundaries, the state boundaries don't make any difference. It's really the electrical connections that make a difference. You can locate a generator anywhere in PJM's region, and PJM will determine whether that generation can be determined deliverable. And once it's declared deliverable, it can deliver its output into the network and serve load anywhere. So it's laws of physics that apply. So a generator can be located in Pennsylvania, Delaware, New Jersey or West Virginia, any place, and still reliably serve load in SWMAAC.

[108] Q Let me ask you this question, do the borders of SWMAAC coincide with transmission bottlenecks in some way?

A No, not at all. It's—again, PJM has determined certain Locational Deliverability Areas to evaluate if

there are any limitations to import power into those areas, but none exist at this time.

Q Okay. We've heard SWMAAC in this trial referred to as a locational delivery area or an LDA, can you explain briefly what that means?

A Sure. Again, as I said, PJM historically has determined these Locational Deliverability Areas as part of their streamlining their analysis process to make sure that if in past history there might have been a transmission limitation that would have restricted the ability for generating resources to serve load in that particular area. So they've created these subregions, if you will, of PJM to do their analysis against. And SWMAAC was one of the areas that they've selected to do the analysis against.

Q Do you know why PJM models SWMAAC as an LDA?

A It's required under the tariff basically is the reason that SWMAAC still exists as a Locational Deliverability Area.

Q So Mr. Wodyka, have you evaluated CETO and CETL with respect to SWMAAC?

A Yes, I have.

Q Can you just explain very briefly, because we've heard [109] these concepts, can you tell us what CETL is and what CETO is?

A Sure. CETO is the Capacity Emergency Transfer Objective, this is—as we were just discussing a few minutes ago—this is the value that PJM calculates based upon a, again, a statistical probability analysis of transmission serving load. The requirement is the transmission has to be able to serve load one day, and result in an outage one day out of

every 25 years. So based upon the statistical analysis they determine, from a reliability perspective, of how much the transmission system value is worth importing into any Locational Deliverability Area. That's the CETO value. That's the objective in order to ensure reliability for that particular region.

Q And have you evaluated that specifically with respect to SWMAAC?

A Yes, I have.

Q And where does one find CETO and CETL values for SWMAAC?

A Again, they're on these planning parameter pages we were just reviewing.

Q By the way, how does one go about uncovering these planning parameters if they want to look at them?

A They're publicly available on PJM's website.

Q Can you put the demonstrative PD-50 on the board. Can you tell us what this is, Mr. Wodyka?

[110] A Yes, this is a summary of the CETO versus CETL values for the time period of 2011 through the current planning period of 2015/16.

MR. KLEINMAN: Your Honor, before the line of questioning starts, I'm going to make the same objection I made before.

THE COURT: Well, the principal is there for 2015/16, why don't we just limit the testimony to that.

MR. KLEINMAN: Thank you, Your Honor.

Q (BY MR. PLUNKETT) Okay. And that will save time. Let's focus on 15/16.

A Okay.

Q Tell us what the blue is and what the red is?

A Sure.

Q And forget the pie charts on top, tell us about the bottom of the chart.

A The numbers published by PJM, these represent—the blue bar represents the CETO value, which is the objective that you need to have to ensure reliability for the SWMAAC region. And the red bar represents the CETL limit, which is the system limitation that they calculated that would restrict how much transmission could be brought in. And the comparison between the CETO value, which is the objective, and the actual limitation provides a 177 percent margin, or 70 percent margin above the CETO limit.

[111] Q So could I look at that and say 4,720 is what SWMAAC needs to transport?

A Yes, that's what they need to—for the—based upon the reliability analysis.

Q Okay. And then could I say that the red is what they're capable of transporting?

A Yes, that's exactly what it means.

Q And there's a 77 percent margin for 15/16?

A Correct.

Q Okay. How does that inform your opinion about whether to solve some reliability crisis in SWMAAC, it makes sense to say you need to build generation in SWMAAC and not in any other state?

A Well, again, this clearly demonstrates that the transmission system supporting SWMAAC is a very,

again, strong transmission system. And these margins are very favorable to allowing generation outside SWMAAC to serve load in SWMAAC.

Q Did you also review the results of the annual capacity auctions in determining—reaching an opinion on this locational issue?

A Yes, I did.

Q Let's go back to Defendant's Exhibit 290. Page 15. We've all seen this several times, so very briefly tell me what this is and what it shows about the auction results with respect to SWMAAC?

[112] A Right. This shows that the auction results for the four areas identified for PJM, or the RTO as a system, East MAAC, sub area of the SWMAAC subregion, and then the MAAC region. And then if you follow through the lines, the first couple years that SWMAAC had separated from MAAC, and in 2010/2011 those values came together, and the SWMAAC and MAAC values track together from that point forward. And there's other variations between EMAAC and MAAC and different things. But generally focusing on SWMAAC versus MAAC as a system, those numbers become the same, you know 2010 and beyond.

Q So for the last six auctions, the price in the — the clearing price for SWMAAC has been the same as MAAC, there's been no price separation?

A That's correct.

Q Okay. And I believe that is portrayed in a map that we've all seen many times on the right-hand side, that is PD-45, do you see that?

A Yes, I do.

Q Is that an accurate representation of the results of the 15—excuse me—yeah, the results of the 15/16 auction?

A Yes, it is.

Q And it's also an accurate portrayal of what the lack of price separation would show for the past six auctions?

A That's correct.

Q What does that information—withdraw that question. How [113] does the lack of price separation between MAAC and SWMAAC for the last six auctions inform your opinion about the locational restriction to SWMAAC?

A Well, what this says is resources throughout the MAAC region, and again, I didn't mention this earlier, but the MAAC system is synonymous with the old PJ region when there were the eight investor-owned utilities forming the power pool, that's the MAAC region. Any resources in the MAAC region, which is not a small region by any stretch of the imagination, it's probably 70 or 80,000 megawatts of resources in MAAC in general, that any of those resources, based upon the auction results, can be used to serve the capacity requirements in SWMAAC.

Q Just to conclude this discussion of your last opinion, let me ask you, in your review of the information in this case, in preparing your reports and preparing for trial, have you seen any information that in your expert opinion would justify the requirements that new generation be built within SWMAAC to serve a purported reliability interest in SWMAAC?

A No, I have not.

Q Okay. I have one more short topic, because I don't want to have you come back here again. And that is to discuss the opinions, very briefly of one of defendant's experts George Lore, who I believe we will hear from later this week, or at some point. Did you review the report that Mr. Lore submitted [114] in this matter?

A Yes, I did.

Q Okay. And you responded to that in your rebuttal report, didn't you?

A That's correct.

Q Okay. I just want to ask you about a few of Mr. Lore's opinions and get your response. Mr. Lore states that reliance on long distance transmission lines presents reliability issues; is that accurate?

A I disagree with that opinion.

Q Why?

A The electric power system, as it's grown up over the years, relies on generation resources across large territories. These systems have been properly planned, designed, and operated for many, many years using generation resources remote from the load. Look at the size of the region of PJM, there's many generation resources throughout this region that are supplying load across transmission lines. Connecting a generator closer to the load doesn't eliminate any of the problems or doesn't improve reliability in my opinion. Transmission problems can occur at any point on the system, whether it's a long distance transfer or whether it's a short distance transfer. The problems can occur, like I said, at any time. So it's my opinion that that doesn't improve reliability at all.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, *ET AL.*,

Plaintiffs,

v.

DOUGLAS NAZARIAN, ET AL.,

Defendants.

March 7, 2013

DAY FOUR TRANSCRIPT OF BENCH TRIAL
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[85] for the record.

THE WITNESS: My name is Odon Sherman Knight. 0 D 0 N. Sherman, S H E R M A N. Knight, K N I G H T.

THE CLERK: Thank you.

DIRECT EXAMINATION

BY MR. EISENSTAT:

Q. Thank you. Mr. Knight, would you please describe your position with Competitive Power Ventures?

A. I'm a senior vice-president of marketing and origination.

Q. And what did you do prior to joining Competitive Power Ventures?

A. Prior to Competitive Power Ventures, I had my own consulting company from 2003 to 2006.

And prior to that, I worked at PGE Energy Trading where I was responsible for the commercial optimization and marketing of approximately 7,000 MWs of generation both the northeast as well as west.

Q. And the 7,000 MWs of generation, was that operating generation?

A. Yes.

Q. Would you describe please what you meant by commercial optimization?

A. I was responsible for the daily selling of the electricity into the wholesale market. I was responsible for the procurement of fuels, I believe it was natural gas, coal. We

* * * *

[126] The role of the developer standpoint is putting in a large capacity project, like a combined cycle like CPV Maryland is. I think it's irrelevant.

Q. That's one word.

A. And—

Q. Why do you say that? Explain that.

A. May I explain?

Q. Sure. Sure.

A. I mean, that's a tough question, but I mean at the end of the day, the new combined cycle facility is an expensive machine. And you're not going to receive all your cost backing in the first year. You've got to look for a long-term stream of payments to assume that you're going to receive your—enough money back to warrant the investment.

If you take, for example, PJM, and just to keep the math simple, if you assume your asset's only 20 years, which a new combined cycle typically lasts much longer than that, but just assume that it's 20 years, and just assume that energy and capacity margins are roughly 50/50, that would mean that the first year of capacity, which is what is presented on the Base Residual Auction, represents roughly 1/40 of your future energy streams. I think that's like two and a half percent of your total revenue stream. So you may be fixing two and a half percent, but you'd still have 97.5 percent of it still out there floating around that you're not sure of.

[127] To the extent that you can somehow gain knowledge on what the RPM price is, as a view toward the future, maybe, but they've been so volatile in the

past and the rules have changed, you know, at least from CPV's perspective as a developer, we have not developed based upon any signals associated with RPM or capacity markets in general.

Q. When did CPV begin developing the Maryland project?

A. I believe it was in 2006.

Q. Do you recall what the capacity price was then?

A. 2006, I believe the capacity, it was a different regime than the RPM, but I believe it was 25 cents, maybe a dollar. Q. 2006 was the year of the RPM settlement?

A. I believe—was it, I'm not sure if it was 2006 or 2007. The first auction for RPM occurred in I believe 2007 for 2007.

Q. Do you have any recollection as to roughly what the price was then?

A. In 2007?

Q. Yes.

A. Prior to the RPM?

Q. Yes.

A. Yeah. That's maybe 25 cents as opposed to $167, yeah. In other words, it wasn't a meaningful revenue stream at all.

Q. So why did you start?

A. Our company typically looks at the fundamental need of new generation and bases its decision to start development based [128] upon where we expect new generation is needed regardless of what the current market pricing is.

When you look at a SWMAAC area, 2006, we were looking at an area that was transmission constrained and remains transmission constrained, but there's also, I believe, something around 93 percent of the assets are older than 20 years. I believe 47 percent of the assets in SWMAAC are older than 50 years old or older.

So a huge portion of the SWMAAC service territories are being—depend upon basically the Korean War era power plant. So we look at the age of the facilities transmission constraints. We look at the load growth and determine what seems like a reasonable bet to make to start to conceptualize and site and permit a new power plant.

Q. To what extent do you look at LMPs, Locational Marginal Prices?

A. From a developer's standpoint, the reason why I'm couching this, I do work across business line, so I work both in development as well as with existing assets.

From a developer's perspective, within the PJM territory, you know, we will look at different locations. If we're interested in say the SWMAAC area, we will look in different locations of what is a feasible site for a power plant and then look at the historical relationship between those different sites within SWMAAC and differentials between [129] the LMPs between those versus what the capital cost would be.

Q. Now, from an asset manager's perspective, the management of an existing asset, to what extent do you believe that the capacity market sends a meaningful price signal?

Well, from—if you already own existing asset and you're looking at the capacity auction, a good portion, or your entire construction costs at that point are sunk before you have the asset.

So what you're really looking at a couple choices, if you're—if you're in a situation where you feel like you can't cover your costs. You're either going to make money or you're not bidding in the capacity auction.

So the situation that we were working with, in PJM specifically, we were managing the Liberty Electric Plant just outside of Philadelphia. And so we would look at does it make sense to continue to run based upon what the capacity price is? And if you feel like you can earn more revenues by running as opposed to shutting down, then you're going to keep going.

So it is a meaningful price signal from a standpoint of an existing asset, making that retirement decision.

It's also meaningful from an uprate standpoint. In the Liberty example, we were facing a situation where we could increase the firing temperature within the gas turbine, which effectively allowed us to put out another, you know, 10, 15, 20 MWs on to the grid.

[130] In order to do that, we could qualify that as capacity. The capital cost relative to where the RPM auction said that we're going to get a one-year payback, absolutely, we'll do that, and we increased the output of the facility.

So I think from an uprate standpoint that has the short payback periods, or from the standpoint of you're making a retirement decision, it is a meaningful signal.

THE COURT: Mr. Knight, the thing you just described, which is increasing the capacity that's going

to cost you Z dollars, you'd have to decide you're going to do that before you bid into the capacity auction; that is, you're committing the capacity without knowing what the price is?

THE WITNESS: Well, if you're doing an uprate, you can take those incremental MWs and bid a price.

THE COURT: As to that, let's just take—and I really—this is a helpful exhibit, which I'd like to ask you a lot about, but you made a point here, and don't worry about numbers, because we—it's going to cost you $10 million to increase your output a certain amount.

Okay. It's going to increase, it's going to cost you $10 million to increase your capacity by MWs, or okay.

And that's so you could bid into the capacity market at a price, which I'm just going to say is 120, that for that marginal increase, and know that, well, if you don't clear, you're not going to do it. But if you do clear, you will do

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, ET AL.,

Defendant.

March 7th, 2013

THE ABOVE-ENTITLED CASE CAME ON
FOR A BENCH TRIAL BEFORE THE
HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:29 p.m.)

THE COURT: One last question to you please, Mr. Knight. Just the X number is tied not just to the capacity, but also to the—in other words, using these artificial numbers you would compare your X to 487, which is both your energy profit and your capacity receipts for the given year?

THE WITNESS: Yes.

THE COURT: Okay. So it's not just the capacity?
THE WITNESS: No.

THE COURT: Okay. Thank you. Oh, I guess—no, let's—enough. Thank you. All right. Go ahead, Mr. Meyer.

THE WITNESS: I'm more than happy to walk it through the contract, but's both the energy margin and the capacity.

THE COURT: Well, I—I've stumbled through it already. I'm sure I will walk through it again.

MR. ERWIN: You're doing such a good job for us, Your Honor.

THE COURT: I didn't know I was working for you. All right. All right, Mr. Meyer.

CROSS-EXAMINATION

BY MR. MEYER:

Q Good afternoon, Mr. Knight.

A Good afternoon.

Q At the risk of returning us to the district of

* * * *

[11] for Differences, the pricing Contract for Differences in this case that the PSC has ordered the EDCs of Maryland to enter into with CPV, you're familiar with that contract, right?

A Yes.

Q Thought so. And under that contract CPV would be required to participate in PJM's capacity markets?

A Yes.

Q Would be required to clear the capacity market?

A I don't think there's actual requirement to clear the capacity market.

Q I'm sorry, perhaps I misspoke. Would be—in order to be compensated under the contract, would be required to clear the capacity market?

A Yes. In order to receive payments under the contract, I believe that we need to clear.

Q Right. And it's also true, with respect to the energy side of the contract, there are no payments made to CPV, except in connection with each unit of energy that gets sold into PJM by CPV?

A I guess I struggle a little bit, and I think we—breaking—there's a pretty long formula within the contract for CPV Maryland. And in that there's—I believe what you're referring to is there's a netting for—that's termed in the contract of the contract capacity payment. And there's also a netting for—I can't remember the term, but I think it's [12] something about energy, and then there's other revenues. And so there's a net payment for a variety of different formulas in there. And under—if we are speaking the same, and I think it's sometimes helpful to actually get into the contract because it is a formula that

determines that payment. There is a piece of that formula that is dependant upon the actual energy revenues that CPV Maryland earns from selling its energy. Is that helpful, or at least responsive?

Q The actual energy revenues, stay on the energy side, they're basically as—we could look at the contract if we wish, perhaps if the Court is interested we could spend that time. But just to try to summarize, there are essentially two netting functions that go on to determine the final payment that flows one way or the other between CPV and the EDCs, correct?

A I think there's two parts of a formula. I'm not sure both are netting—

Q We could go back over—

A There's multiple plus and minuses.

Q We could go back over, but there's a contract capacity payment, a contract capacity price that gets netted against the PJM clearing price on the capacity side of the contract, correct?

A Yes.

Q And then on the energy side of the contract, there's a [13] what's referred to as a heat rate calculation to determine the fixed price component of the contract, right?

A That's correct, it represents marginal costs.

Q And there is a—the floating price is whatever price is earned by CPV when it sells a unit of energy into the PJM market?

A The part that I can't quite remember is whether or not it's the price or the actually energy revenues that CPV earns, but I'm not sure that—

Q Well, the revenues would be the clearing price in the energy market, times the number of units sold in the energy market, right?

A Yes, it would be within that formula within the CfD. I just can't remember whether or not it actually referenced the price or whether it just referenced the energy revenues.

Q You can't earn energy revenues without selling units into the energy market?

A Correct.

Q Okay. And you can't calculate the heat rate without a quantity number, can you?

A What do you mean a quantity number?

Q Knowing how many units were generated, units of kilowatt hours or megawatts days were generated?

A Well, heat rate you can calculate without that.

Q Well, I mean the—you can apply the heat rate to a [14] quantity to determine an amount, right?

A An amount of what?

Q Pardon?

A Amount of what? I'm really, I'm trying—I'm trying to get to what you're trying to get to. I just—a heat rate is determined by efficiency of the power plant. In our case, within the CfD it's a stated number. So I'm not sure where you're—

THE COURT: The heat rate is the same for one unit or ten units, this is the rate.

THE WITNESS: Exactly.

THE COURT: I'm not sure what the question is.

Q (BY MR. MEYER) Just trying to—without belaboring the review of the contract, I'm just trying to get to what I think is a very simple point. And that is—let's just start with—deal with the capacity side of the contract. You would agree that, again, the—this pricing contract requiring CPV to participate in the market, and not providing any compensation unless CPV clears the market, works the way that's depicted here on the capacity side. And, again, CPV is—the only sale of capacity that CPV is making is a sale to the PJM markets, you agree with that, right?

A Yes, the one thing that I don't entirely agree with is just the depiction that says "total payment," because it's missing the energy portion.

[15] Q It's total—the total capacity payment on the contract, the total portion of the contract involving capacity payment. We can look at the contract, is calculated exactly this way, is it not?

A I'm not sure if it matters to belabor this point or not, but the contract in the CfD for Maryland includes both a portion, I believe, of you know, associated with capacity pricing and a portion that is associated with energy pricing. And this demonstrative shows just the capacity side of it, it doesn't show the energy side. That's—and so when I look at it and it says total payment equals CCP, that's not entirely true because we're missing the energy portion.

Q Right, but this —

THE COURT: If it said "Total Capacity Payment," that would be okay.

THE WITNESS: No, I think it requires another arrow from CPV going down to the PJM energy markets, and that coming around to CPV And then

the payment structure from the EDCs would be the CCP minus the RPM clearing price plus the—

THE COURT: Is the problem that the exhibit here is not including anything relating to the energy market?

THE WITNESS: Exactly.

THE COURT: So that's—so if we can all agree on that, then total payment doesn't—doesn't mean total in the sense of capacity plus energy, it means total for capacity. Is [16] that where you are?

MR. MEYER: No disagreement here.

THE WITNESS: Okay. Good.

MR. MEYER: No disagreement here.

Q (BY MR. MEYER) So talking about the capacity portion of the calculation. And the capacity portion of the calculation involves CPV selling a megawatt day, or whatever number of megawatt days it clears, it actually sells to PJM. So take one of those megawatt days. With respect to one of those megawatt days, CPV is going to receive from PJM the RPM clearing price, that's the way the contract works, right? I say receive, the calculation will take the RPM clearing price, right?

A Yes.

Q And it will look at a contract price, which is what has been referred to as the magic number from time to time in this courtroom, and it will determine whether the contract clearing price is—excuse me, the PJM RPM clearing price is above or below the contract clearing price?

A Yes.

Q If that RPM market clearing price is below the contract clearing price for that unit of capacity, CPV will receive, as part of the calculation of the capacity side of the contract, a make up payment, a supplement, a net payment from the EDCs equal to the difference between the magic number and the clearing price?

[17] A Subject to saying receive or pay, because it could go either way, depending upon if the magic number is above or below the published index price of PJM. And it's subject to the energy portion, which we all agree is out there as well.

Q All right.

A And that number is then either received or paid between the EDCs and CPV Maryland, yes.

Q Okay. And, again, there's no question about the fact that on the capacity side of this contract, the quantity that is at issue, that is—for which CPV is compensated, is determined by how much CPV sells at auction, right? Sells at the RPM auction that PJM runs?

A My recollection of the contract is that it is capped at 661 megawatts. So if we actually sell more into the capacity auction then the payment structure is slightly different but —

Q Well—

A If we sold 663, the contract flows through on those formulas based on only 661, as opposed to the total amount we sold into the RPM. Auction, but other than that, yes.

Q And if CPV sells 659, for each of the 659 units there would be this comparison between clearing price and the—

A I believe that's correct.

Q Now, you said earlier today that you regard—I understood you to be referring to the CPV contract—regard this as a financial contract; is that fair?

* * * *

[21] we're concerned with covering our total costs.

Q Right, so you—this $167, you referred to that as the RPM clearing price?

A Correct.

Q When you came up with your evaluation of what to propose as the contract price for this contract, you didn't know what this number was going to be, did you?

A No, and we didn't try to forecast forward for the length of the contract what we expected our energy margin or capacity margin would be. What we tried to ensure was that we were covering our variable cost within the energy margin section. And whatever the actual energy revenues and capacity revenues would be this, those would net off in the CfD and we would end up with a fixed price.

Q Right. So you didn't look at market prices—market price levels at all in determining—

A In bidding the CfD, no.

Q No? Whether contract—capacity prices would be $167 or some other number wasn't relevant to CPV in this circumstance?

A With regards to coming up with a price for the CfD, no.

Q All right. And, in fact, what CPV did is CPV, and I think you described this process, is CPV came up

with a set of price terms that gave CPV a sufficient level of revenues to meet its target level of return?

[22] A Yes.

Q And in doing so, CPV, through this contract, was doing what it concluded was needed in order for CPV to come into the market at all?

A Yeah, at the time. Yeah.

Q If you were—if CPV were just out is there in the market, looking to the market for returns, CPV would still get revenues, correct?

A What do you mean by "just out there in the market"?

Q Well, if CPV didn't have this pricing contract ordered by the state of Maryland, CPV would be looking to the market as the source of its revenues, energy—the PJM energy markets, PJM capacity markets, or potentially a contract of some sort with a counter-party that could be negotiated by CPV in the marketplace?

A That's correct.

Q And CPV—after it—or let me back up. You testified earlier that CPV came to Maryland in 2007 looking to develop the St. Charles project?

A I believe it was 2006.

Q Okay. And when CPV did that, CPV anticipated that it would need a long-term contract of some sort in order to build its plant, correct?

A I think in 2006, and potentially in 2007, we were debating internally whether or not, you know, in terms of long-term what [23] that meant. Whether that was, you know, five years, seven years, 20 years.

So there was a number of things changing within the marketplace as well as the, you know, the financing community. I think if we all remember back to 2007, the lenders were a lot more lenient than they are today. And their requirement for what needed to be hedged, or have certainty around, was less than what it is today. So we were definitely looking that we needed a contract. In terms of the long-term, and what the definition around long-term, we were certainly debating the time.

Q So if I understand your answer, perhaps the difficulty was around the phrase long-term. CPV was looking for some arrangement that would hedge its market risk, correct?

A Yes.

Q And that arrangement could take the form of a swap agreement, for example?

A Yes.

Q Or perhaps a Power Purchase Agreement?

A Yes.

Q So it's true, is it not, that there are contracts that involve physical transactions that can be used as hedging instruments?

A Yes. When we speak about hedging, it just means reducing the volatility of what are our emergency margins and capacity margins would be.

[24] Q So maybe an illustration, maybe a simple one, if CPV entered into a Power Purchase Agreement with a buyer of energy or capacity for five or seven years, that could lock in a guaranteed revenue stream as well?

A It could.

Q Now, but that would still be a contract involving a physical transaction?

A It could be.

Q So, let me direct your attention to Plaintiff's Exhibit 3.

And I—we may have come to the point in time when I think it's going to be necessary to ask or to point to the magic number. And I spoke with counsel before the examination. I have a—this document contains the magic number.

THE COURT: Why is it necessary to refer to the—that number. We can have a separate debate into why in the world it's confidential anyhow, since the utilities know it. But putting it aside, why is it going to be necessary to refer to that number at all?

MR. MEYER: Well, Your Honor, I think what I propose with this witness is, I think, a straight forward process where I don't think we need to utter the magic number, but it may—in order to address other evidence in the case that, and to argue around the actual facts of the case, it will be difficult if the number is not in evidence. And I just want to have the witness confirm what I know will be very straight forward

* * * *

[37] make sure that you had an exception filing in front of PJM in time to bid into the May auction, in the event you were awarded the contract, correct?

A I mean I—in general, you know, we make—won't make a decision to bid into an auction until just prior to the auction. But it makes good sound business sense that if you are interested in bidding, when you make that decision you're going to want to bid as low

as possible to try and clear. So we were interested in setting the stage to be as competitive as possible to bid into the upcoming Base Residual Auction. It's hard for me to say that we did that solely for the expectation that we would receive a order from the PSC to start negotiations with the EDCs on a contract, or whether that was, you know, just creating more optionality for us to competitively bid into the Base Residual Auction.

Q Okay. So in that submission you presented to PJM a proposed number that would be the floor on your bid, correct?

A That's correct.

Q That number's been referred to earlier today in Defense Exhibit 265. That proposed floor was $13.95 a megawatt day, correct?

A Correct.

Q And both the market monitor and PJM disagreed with your submission, correct? Disagreed that that floor was a appropriate floor?

[38] A Yeah, they felt the appropriate floor was higher.

Q And ultimately the PJM required the floor to be raised from $13.95 all the way up to $96.13?

A That's correct.

Q Okay. And again, if I understood your prior answer, your motivation was to have as low a floor as possible, right?

A Yeah, our motivation was if we were going to bid, to try and clear the auction.

Q Right and there's some discussion of the market monitors' reaction. And after PJM came back with the

$96.13 number, the market monitor went to FERC to challenge the figure, claimed it should be higher, correct?

A Correct.

Q All right. And that was the discussion about the —

A Project X.

Q —$135—

A Yeah.

Q —Figure that you mentioned?

A Yes.

Q And in the discussion that we had about—you had with your counsel about the market monitor's appeal or petition, market monitor concluded, after—they filed its challenge before the auction was run, correct?

A I believe that's correct.

Q And then withdrew it after the auction was run, correct?

[39 A I believe that's correct.

Q And I think you were clear, but I just want to be sure, that the reason you understand it is as the auction was run, the monitor was able to determine that the price the monitor—the floor the monitor would have required was still below the clearing price?

A Yeah, but I think the specific words that he used is that it didn't harm the competitive markets. I am interpreting that as that he looked at and said we would have cleared any ways and the market price wouldn't have changed.

Q Understood. Now, I'd like to direct your attention to

Plaintiff's Exhibit No. 4. Let me ask you to confirm that board of managers meetings of Competitive Power Ventures Holdings, LLC, are meetings of CPV's holding company executive group or board of managers, correct?

A Yeah, we have a—we have a board of directors, I believe, like any other board, some independent, some are part of the executive team.

Q And these board of managers meetings are held on a periodic basis, and reports are made by executives, officers and employees to the board of managers on a regular basis, correct?

A Correct.

Q In the usual course of CPV's business, correct?

A Correct.

[40] MR. MEYER: I would offer Plaintiff's 4 as a business record, Your Honor.

THE COURT: Well, under the rules it's in evidence when you mentioned it.

Q (BY MR. MEYER) And on page 45 of this document there's a memo—or beginning on page 43, excuse me, there's a memo from Peter Podurgiel to the board of managers in September 2010. And it's regarding thermal development executive summary. And thermal development relates to CPV's development of generating plants that would burn fuel, correct?

A Correct, that's natural gas development.

Q And in the PJM update on page 45, referring to the PJM region in which CPV was potentially interested in developing projects, there's a report to the board of managers regarding PJM capacity auction prices for 2013, 2014, see that?

A Yes.

Q And there's a reference four pages—four lines down from the top, after reporting on the level of RPM capacity prices in the market, "While it is clear that CPC has well sited projects based on locational energy and capacity pricing," and well sited projects would include the CPV St. Charles project referenced above?

A Correct.

Q "The value and term of the commitment, market liquidity falls short of supporting new build economics that can be [41] financed," see that? Do you see that?

A Yes.

Q And that's a reference to the RPM's view that the prices, while not irrelevant, are not sufficient as a basis to invest in any development, correct?

A I think one of the key terms there is the value and term of the commitment. It's a one-year term. If you're looking at a project that as that a 20-year asset life, and you're only looking at the capacity market here, you really are looking at only about two and a half percent of the future revenues that you need. So the term of that transaction being only one year is really, you know, one of the key components that in our view RPM—makes RPM irrelevant from a development standpoint.

Q Okay. And the point being that you wouldn't build based on a single year of revenue commitment, correct?

A On a single year, correct.

Q Now, let me ask you about that MOPR, this Minimum Offer

Pricing Rule. The rule as you understand it, is applied to mitigate an offer made by a new generating facility that actually bids into the capacity auction, correct?

A Yes.

Q That rule doesn't apply with respect to decisions about whether to build into the market—to bid into the auction market, does it?

A I don't know what you mean by that.

* * * *

[45] Q (BY MR. MEYER) CPV urged FERC not to address that contract, and specifically not to address FERC's jurisdiction over that contract in its decision on CPV's market-based rate authority?

MR. EISENSTAT: Objection, the document says what it says. He's still characterizing it.

MR. MEYER: That is what the document says.

THE COURT: Well, if you're going to have an objection to what the document says, point to what it is and read it and then we won't have that objection.

Q (BY MR. MEYER) Do you see Footnote 7 on page 4?

A Yeah, I think it's pretty clear here that we're not requesting the Commission to address or discuss its jurisdiction over that contract.

Q Okay. I'll come back to CPV's—come back to your discussion of strategies for bidding into capacity auctions. You gave an example of a situation where CPV had a plant, or was responsible for bidding for a plant that was existing, and then there was a some additional uprate or some additional capacity that was bid in at a different price; is that right?

A That's correct.

Q Okay. And so would you agree that someone who has sunk costs may have an incentive to bid at the lowest possible price in order to clear the auction?

A Yeah, I'm not sure whether or not I would characterize it [46] as whether or not you have sunk costs. I think that the—if you're avoidable forward looking costs are expected to be smaller than what you expect to earn in your energy margin, it would mean your capacity revenues are complete gravy, and therefore, yes, you would be interested in just bidding as low as possible to clear.

Q But under other circumstances, you would not be motivated to bid as low as possible to clear, correct?

A Yeah, I think if—I mean, the two circumstances I can think of, and I don't know because this is—I'm just speculating here. But one I know concretely because that's what we did with the Liberty plant, is we had an uprate, it had capital costs associated with it. With those capital costs, you know, we wanted to make sure we're recovering the capital costs, and therefore, we were bidding, you know, to meet the cost requirement and the return for those. So, yeah, there's

a reason not to try and bid as low as possible for an uprate.

The second reason, and this is a completely speculative, but if you have a large portfolio, presumably you would want to take some of your generation out of the stack because it raises the price for all of your generation. I believe that the PJM market monitor has mechanisms to curb that behavior by the market monitoring unit. But theoretically, if you have a large portfolio of generation, taking some of that out of the capacity auction so it clears higher is [47] beneficial.

Q You are speculating about whether that actually happens?

A Absolutely.

Q Okay. Just to be clear. Well, so now let me review a few other topics. Actually, before we leave this one, put up Plaintiff's 30. Again, CPV's strategy with respect to St. Charles, in the capacity market, was at least as it anticipated, commercialization strategy was to enter into a long-term Contract for Differences for energy and capacity with the Maryland EDCs, per the Maryland PSC RFP. And based on that strategy CPV's market focus was on ensuring that we clear the capacity auction, correct?

A I don't think at this time we had made the decision to bid. But certainly by this time we were working on our MOPR exception to be able to bid as low as possible to clear the auction.

Q But if you did decide to bid, your commercialization strategy would be to ensure that you cleared?

A Yes, we would—well, I wouldn't say we'd ensure, but we would certainly seek to clear.

Q And if you were allowed to bid zero, you would have bid zero?

A Yes, I think we would have.

Q You described earlier in our colloquy the difficulty in proceeding in under the RPM price signal because of its—the

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

v.

DOUGLAS R.M. NAZARIAN, *ET AL.*,

Defendant.

March 7th, 2013

THE ABOVE-ENTITLED CASE CAME ON
FOR A BENCH TRIAL BEFORE
THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT JUDGE.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

* * * *

[71] then rather than starting Professor Willig—

THE COURT: That's fine.

MR. MEYER:—start him first thing tomorrow.

MR. EISENSTAT: May we indulge—may we have a 15-minute break?

THE COURT: That's fine.

(A recess was taken.)

MR. EISENSTAT: CPV calls Douglas Egan, please.

THE CLERK: Stand and raise your right hand. DOUGLAS F. EGAN, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I affirm that.

THE CLERK: Please be seated. If you would, sir, first adjust that microphone to yourself. That's great. State your name and then spell your name for the record.

THE WITNESS: Douglas F. Egan, D-o-u-g-l-a-s, F, E-g-a-n.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. EISENSTAT:

Q Good afternoon, Mr. Egan. By whom are you employed?

A I'm employed by Competitive Power Ventures.

Q And what is Competitive Power Ventures' business?

A We're in the business of developing natural gas-fired [72] projects, wind-driven projects, and also we manage about 4,500 megawatts of projects that are owned by primarily financial institutions that don't have a management capability for power plants.

Q Who are the owners of competitive power ventures?

A The largest owner is Warburg Pincus, one of the longest-lived private equity funds in the U.S. The other owners of the project are mostly members of senior management at CPV.

Q When was—you mind if I use the term CPV?

A Not at all.

Q When was CPV formed?

A In 2000.

Q Actually before talking about CPV, what's your educational background?

A Went to Dartmouth College and Cornell Law School.

Q And what did you—what was your first job in the electric power sector?

A Coming out of law school I went to work for a law firm Murphy, Kline, Richter and Penny. I probably spent 60, 70 percent of my time on one client, which was the Connecticut Resource Recovery Authority, developing waste energy projects in Connecticut.

Q And then what did you do?

A Went from there to a small development company, [73] Intercontinental Power Company. We developed a 600 megawatt project in Virginia, 300

megawatt project in New Jersey, and a 300 megawatt project in Massachusetts.

Q When did you go to Intercontinental Energy?

A That would have been about '87.

Q And after leaving Intercontinental, where did you go?

A In '91 I went to another development company, the J. Makowski Company. And I worked for J. Makowski Company for about two years before the company was purchased by U.S. generating, which then, you know, series of transactions morphed into PE&G Generating Company.

Q Are you familiar with the term IPP?

A Yes.

Q Stands for?

A Independent Power Producer.

Q Was Intercontinental Energy an IPP?

A It was.

Q Was it one of the first IPPs?

A It was one of the early movers, absolutely.

Q What about the J. Makowski Company?

A Likewise, most of the early IPPs were either located in the Northeast or in California. And I was fortunate enough to work with a couple of the first projects in the northeast.

Q What are your present responsibilities at CPV?

A Well, one I think I'm pretty good at my staffing. And, [74] frankly, that's one of the most important things a CEO can address. And I feel like I've got a

very good senior management team. But also we look at, you know, what are the regions of the country where we think we can succeed. And further going, you know, from broad down to the narrow, looking for specific areas where power project would be appropriate. And then going to the siting level. Now, usually when it's going to the siting level, that comes to me from our staff. And I accept it or not.

Beyond that, it's also dealing with our primary shareholder. We've been with them for 13 years, which is very unusual for private equity. We've got a good relationship with our funder.

Q Are you referring to, Warburg Pincus?

A Warburg Pincus.

Q Since beginning in the industry, how many projects have you successfully developed, roughly, you don't have to be exact?

A It's about 25. There were three waste energy projects, five wind projects, and then the rest would be natural gas projects.

Q So about 25 projects in 30 years?

A Yeah.

Q Could you describe some of CPV recent projects?

A Well, right now we have a project in Palm Springs, [75] California, it's an 800 megawatt simple-cycle facility. It's designed to firm up the wind in the San Gorgonio Pass, which is one of the major passes from the inland side of California to the coast. That project, it was about a billion-two financing. And we should be done with the project by May of this year.

Q What is the name of that project?

A It's the Sentinel project.

Q And have you—are you developing any other projects in California?

A We've got a site in Northern California in the PG&E area that is we call the Vacaville project. It's relatively immature. But we have done, about four years ago now, we built the Colusa project in Northern California—or I should say we developed it. We sold it to PG&E at commencement of construction. And that was a 650 megawatt combined-cycle project.

Q What about in the wind area?

A We just finished a sale of our Cimarron project, which is 170 megawatt wind project in Kansas. We sold it to NextEra in December of 2012, after we had completed construction.

Q And any other wind projects, Keenan for example?

A Keenan was our first wind project. We did it in two phases. The first phase we sold to Oklahoma Gas and Electric. It's located in Oklahoma. The other we entered into a Power Purchase Agreement with OG&E, and run that project and own that [76] project outright.

Q Do you have any partners in any of your current projects?

A We do. In the Sentinel project, GE is a 25 percent partner.

Q General Electric?

A General Electric Company. And Diamond Energy, which is a subsidiary of Mitsubishi, has a 50 percent share of that project.

Q Are you also developing a project in New Jersey?

A We are. And in that project, we've got—we still have all of the equity in that project.

Q And what's the name of that project?

A The Shore project.

Q And obviously you're developing St. Charles?

A And we're developing St. Charles, again with partners, Diamond and Toyota.

Q How long does it take to develop a competitive power plant?

A Well, you know, when I started out the business, the rule of thumb was that the project would take two years to develop, two years to build, and you'd be about $10 million into it by the time you broke ground. Today, you know, we're seeing that development time is anywhere from three—if everything is perfect—three years, to you know, frankly, more, usually [77] five or six years. Litigation has become more of the norm. This isn't—this isn't unique. And in terms of the amount of money spent by the time we break ground, you know, frankly, it's usually $40, $50 million or even more.

Q Is it typical that power plants—is it typical for power plants to require a variety of municipal and state permits?

A Yes. I mean, it's—by the time you count everything that's on the local, the state, and the federal level, you know you're talking about 35, 40 different permits or approvals. It takes a lot of time.

Q Tell us about your—well, as a general matter has it been more difficult for you to develop plants

where a multiple of municipalities and states are involved?

A Yes, we have. It's—you try not to have multiple jurisdictions, because it's always complicated if you do. And frankly, it can have very bad results. When we were at the—at PG&E, we developed a project in Arizona. There were several projects built in the same area, designed to serve California rather than Arizona per se. Arizona decided not to build a transmission line that they had committed to. And that was a project that we developed when I was at PG&E. And as it happened, a few years later it came back to us as an asset management job. And it has been under water from day one because of essentially a dispute between Arizona and

California. So we try not to be in multiple jurisdictions.

[78] Q In that particular instance you would need to be permitted essentially in both Arizona and California?

A You didn't have to be—you didn't have to have permits from both, but we were reliant upon the transmission line that the two states had agreed upon. And then Arizona changed its mind essentially.

Q What are the chances today of being able to build a power plant in PJM?

A Well, it depends on the approach you're going to take. We feel strongly that if you're going to build a large power plant, spending you know, somewhere in the range of $700 million, there ought to be some degree of long-term certainty that you'll be able to get your investment back, and eventually earn a return on that investment. If, on the other hand, you want to

become a merchant generator, it's certainly much, much easier to get through, because you know, you're really just going through the MOPR process. Whereas, we were looking for that economic underpinning that we felt like we needed to spend the money on this project.

Q Now, do you mean it's easier to be a merchant plant or you can do it more quickly, but you might not necessarily succeed? I don't want the record to be unclear on that.

A We are starting to hear about the odd merchant plant here and there. You know, the LS power project in West Deadford is the most notable exception. But it's still the exception—

[79] THE COURT: What do you mean when you say merchant?

THE WITNESS: When we say a merchant plant, we're talking about a plant that gets built without a PPA or an equivalent to a PPA. So, you know, a Contract for Differences or a Power Purchase Agreement separate you from the merchants. But it also might be a, if you could do a very long-term gas contract at some kind of a discount, which is something that's being discussed in the market. That could take the place of a Power Purchase Agreement because it gives you a certainty of a spread to the market that would allow you to recover your investment. So the merchant is a project that goes into construction without those kind of financial underpinnings.

THE COURT: Speculative.

THE WITNESS: Speculative.

THE COURT: All right.

Q (BY MR. EISENSTAT) Are any of the plants that your company presently manages formerly merchant plants?

A Most of the projects that we run in or asset management business were merchant plants built in the 1999 to 2002 time frame, which was a time when a lot of new gas-fired projects got built, and almost all of them on a merchant basis. And after Enron imploded in the fall of 2001, the liquidity in the marketplace evaporated, Enron obviously folded, as did several other trading companies. And literally, dozens of projects went belly up.

[80] And frankly, we created our asset management business to take—to help the financial institutions that were inheriting these power plants that they didn't know what to do with. We gave them a management team for hire. Frankly, I thought it was a gig that would last for two or three years. But, you know, here we are, you know, more than ten years later, and we still have 4,500 megawatts of stranded merchant projects that are struggling to get along.

Q Did—during that period of time, the late 90s, were developers expectations as to how competitive the markets would be, were those expectations higher than they are today?

A Yes, without a doubt. At that point in time, the expectation was, and certainly I brought in on this as well, that there were going to be massive consolidation in the power generation industry. And that the country would have, instead of, you know, hundreds of separate generation companies, there would be 10 or 20. And so there was a time, '99, 2000, when a fully developed, but unbuilt project could sell for, you know, four times the amount of money in it. So you know $20

million spent, someone would buy that project for $80 million. So there was a certain amount of hype and hysteria in the market. But for a while it was real until, you know, the underpinnings fell out when Enron imploded.

Q Let me get back to the development business a little bit. Are all potential sites in PJM equally suitable for power plant [81] development?

A No.

Q Why's that?

A You have location, and you know, that takes into account how close you are to schools, to residential areas, to parks. So you've got to look—make sure it's in an appropriate location for a power plant to be.

You also have to get yourself located near the gas lines, near the power lines. You know, it seems kind of self-evident, but if you're going to build a gas-fired power plant you need gas and you need transmission lines.

And then beyond that, it's also a question of, I would say, sort of historical, you have to do a historical search of your site, I've certainly seen in my career times when, you know, we discovered that there was a civil war burial ground right in the middle of a proposed power site, that was in Virginia. And you know, there's nothing to do at that point but walk away. So there are a lot of different elements to take into account.

Q If you're a wholesale generator, and you're selling into a pool, into an RTO, into the grid, why does it matter where you're located relative to load, does location matter in that sense?

A It does matter. And you know, over time, as you look at what's happened at PJM over the last eight or nine years,

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 8, 2013

BENCH TRIAL DAY FIVE MORNING SESSION
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[2] PROCEEDINGS

THE COURT: There are two things that I would like to ask you to clarify, although not necessarily at this minute, and I don't know if it's this witness. I just would like to understand it to be sure.

And that is to what extent does clearing the capacity market have an effect on the cleared generators sale into the energy market?

And that is, it may make no difference at all whether you clear or you don't clear, you sell the same way at the same price or there may be some restriction, and that could be helpful to fill it out and, secondly, the particular meaning of this market-based rate transaction ability and exactly what it means.

Again, these may not be very important to the case, so at some point, and I would like you to explain that. But I don't want to interfere with the witness's flow and whatever he's doing. As I say, this is not urgent. Okay.

MR. MEYER: Very well, Your Honor. We will endeavor that.

Plaintiffs call Professor Robert Willig.

THE CLERK: If you would stand, please, and raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would, sir, [3] adjust that microphone to yourself.

THE WITNESS: Or myself to the microphone.

THE CLERK: A little lower and we've got it. State your name and then spell your name for the record.

THE WITNESS: My name is Robert Willig. W I L L I G, as in George.

THE CLERK: Thank you. Counsel?

DIRECT EXAMINATION

BY MR. MEYER:

Q. Good morning, Professor Willig.

A. Good morning, Mr. Meyer.

Q. How are you employed?

A. I'm employed as a Professor of Economics and Public Affairs at Princeton University. I also consult.

Q. And what do you teach?

A. I teach economics for public policy. I teach microeconomics generally. And I teach a course typically in legal and administrative regulation of markets, which is an awfully, how should I put it, offputting title for a course that's really about competition, policy, regulation and competition.

Q. Could you explain a bit more about what that is?

A. In a few hours, yes. That is the course which starts with students who have already learned a good foundation in microeconomics. Hopefully from me. These are students in the [4] Woodrow Wilson School basically, which is the unit of Princeton, which is the School of Public and International Affairs. So these are students who are bound for careers in public policy, Public Service. And I teach them basically how to put themselves in the position of regulators or of competition or antitrust officials, both domestically at the local level in U.S. and also around the world.

We have a very international body. And I teach them how to use economics to figure out the answers to questions posed by disputes about what is competition versus what is anticompetitive and what is good regulation in terms of impacts on the public interest versus regulation, which actually, usually unintentionally, but which nevertheless could work against the public interest.

Q. What education and experience do you have in the field of economics and regulatory policy?

A. I studied some of these things in college. Also in the master's program at Stanford, and then I earned a Ph.D. in economics at Stanford University in 1973. And the topic of my research, my Ph.D. dissertation, was about how to judge whether policies are good or not from the perspective of society when those policies affect prices and also might affect the nature of products. And that in effect was the title of the dissertation.

My first job after school, I was teaching actually [5] during graduate school, as a job. But after I graduated, I went to Bell Laboratories in the pure research arm of Bell Labs, studying and doing research on the economics of regulation.

The Bell system at that time made the wise decision that perhaps the state of public understanding of economic regulation might be more important to the future of the company than the next transistor or the next foible of the telephone network. And of course, they were quite right. They were walking into antitrust suits and regulatory revolution at the time.

So I spent four or five years at Bell Laboratories thinking about regulation generally, and with specific application to telecommunications.

And then I moved to Princeton to that post in the economics department and the Woodrow Wilson School where I've been teaching about these things ever since doing research, writing about competition, and regulation, and working hard in applications to a wide variety of different industries including infrastructure industries like energy and communications and transportation, among many others.

Q. Have you had experience in government?

A. I have had experience in government. I spent time as a member of the New Jersey governor's task force on market pricing of electricity, which is certainly pertinent to some of [6] the issues that have been discussed in this case.

And then I spent two years in the U.S. Department of Justice serving as Deputy Assistant Attorney General within the antitrust division, which functionally was the post of chief economist. And I'm not a lawyer and don't ask me whether I ever aspired to be.

Q. Okay.

A. But nevertheless, that was my official title in the Justice Department.

Q. Can you describe the research and writing you've done in this field?

A. Yes. Well, I continued the theme of my Ph.D. thesis work on trying to forge analytical goals to help policymakers understand what the impact of policies are on consumers, on purchasers of things, also on the supply side of the economy, so as to in balance make better decisions with regard to policy specifically toward industries.

I also have done lots of research on the way the rules of the road ought to work, what are good rules for

governments to promulgate at all levels with respect to the operations of business, industries generally.

I speak a lot on those subjects with respect to individual industries, but also with respect to the overall framework of rules and attitudes that ought to apply across entire economies.

[7] I've done consulting work at the level of helping countries to set up their infrastructure systems should energy be privatized or should it be in the public domain? If it's public, how should it be managed?

And if it's private, does it need to be regulated? And if so, how should it be regulated? What should the regulatory framework be?

I've worked through the World Bank and through the Inter-American Development Bank, and through OECD on those kinds of topics, actually appearing in different countries and trying to figure out what sort of regulatory systems they ought to adopt.

I've also done that in the U.S. Government. I've appeared many times before, for example, what used to be the Interstate Commerce Commission and is now the Surface Transport Board, talking about transportation regulation, railroad regulation, re-regulation, deregulation, a long path. But a very important one.

I've done the same thing in telecommunications before the FCC, and I've appeared before the FERC a number of times and also consulted with the private sector clients, companies involved in electricity, investor-owned utilities, generation companies, again, asking questions and trying to analyze the right answers with respect to issues like market structure and again the rules of the road, how should these markets be [8] regulated or not regulated.

MR. MEYER: Your Honor, I would tender Professor Willig as an expert on the organization including regulation and competition and economics as those matters relate to policy toward the electricity power industry and public interest.

THE COURT: Sounds all right. Counsel, any questions?

MR. KLEINMAN: No objection, Your Honor.

BY MR. MEYER:

Q. Professor Willig, you've reviewed the actions taken by the Maryland Public Service Commission in the case 9214?

A. Yes.

Q. And have you evaluated the economic and regulatory policy implications of those actions?

A. Yes, I have.

Q. And could you summarize the opinions you've reached in this case? And perhaps it would help if we referred to plaintiffs' demonstrative 72.

Is this the slide that you prepared, Professor Willig?

THE COURT: Excuse me a second. All right. I also understand that from time to time you folks are going to want a recess. Whenever you want is fine.

MR. MEYER: Thank you, Your Honor.

A. Yes, I did prepare this slide.

[9] Q. Could you summarize the principal opinions you've reached with respect to the matters at issue in this case?

A. Yes. So three principal conclusions and the questions underlying these conclusions very much

govern my analysis of what the PSC did and the pursuing the contract for differences that emerged, out of the order of the PSC.

And so the first page of conclusion is that the order of the PSC and the ensuing CfDs when implemented will actually set a price for wholesale sales of energy and capacity.

And that that price set by the PSC order and the contract differences will displace – will take the place of the price that PJM auctions are designed to set.

So this placement of the PJM price, which I understand to be regulated by the FERC, by a different price, actually set by the PSC order and the CfD, that's my first conclusion.

Excuse me.

The second conclusion is that, in that respect and others, the PSC order and the CfDs actually get in the way of FERC's policy goals. It's not just the mechanical change of one price to another, but that change with the apparatus surrounding it interferes with FERC's stated policy goals.

Third conclusion is again the order and the CfDs needlessly favor the development of new generation or other forms of capacity in this market in one region and that region [10] exists inside a broader market, and that broader market is fundamentally interstate.

And so we're talking about a region, which is being favored by state action, even though that region is part of a market that's broader than that region, and extends across state lines.

Q. Perhaps it would be useful for us to begin by discussing an orientation for your further views what exactly are energy and capacity and how they're

related to one another? And perhaps this will be to some extent responsive to the Judge's question as raised this morning.

A. Great.

Q. Can you please put up plaintiffs' demonstrative 5?

I don't know if this is a useful depiction.

A. What number is that, counsel?

Q. It's plaintiffs' demonstrative number 5. You don't have it?

A. I've got it.

So the demonstrative shows in the middle of the page two different markets. They're side by side as they should be. One's called the PJM energy market the other PJM capacity market.

Energy market is a place where literally energy is transacted. Energy, we've heard various descriptions from this chair over the last week of whether they're electrons

* * * *

[26] the number doesn't matter, you bid in your capacity. So when they say turn on the switch, you turn on the switch, and you're producing.

But in order to turn on that switch for one minute, you have got to spend a million dollars to have everything ready for you to turn it on. That's what I'm talking about. It's for this year, it's whatever it's going to take to have your ability to start the production line.

THE WITNESS: Right. So if you're going forward cost—

THE COURT: And indeed, if they bought your capacity and you never sold one MW of electricity during the year, you'd still have, it would still cost a million dollars, because since you have to be available, that's why you're getting your payment, and that's the cost I'm talking about.

THE WITNESS: Okay. And so let's call that, what, overhead, want to call that overhead?

THE COURT: I'm happy calling it overhead, recognizing I'm going to eliminate depreciation.

THE WITNESS: Okay. I like that.

So it would make sense to bid an amount into the capacity auction that after your margins from your energy sale, because the production of the energy also requires these overhead expenses –

THE COURT: Well–

[27] THE WITNESS: —what they'll need beyond the margin.

THE COURT: I want to be understood, when Mr. Knight was talking about it, or at least the way I'm looking at it is, the energy market, you want to get, for every MW you sell, you would like to get your marginal costs of producing that MW plus something more, and that you're not in that market – well, put it another way. I see that market as being a profit on your marginal cost.

THE WITNESS: Say it again.

THE COURT: You want to say some of that's going to feed back to cover your overhead, okay. But I thought that the capacity market was theoretically supposed to pay you for your fixed costs so that you recovered, even if you didn't sell anything?

THE WITNESS: Well, the operating of the plant also earns you some margins on your energy sales.

THE COURT: Oh, yes, yes.

THE WITNESS: So even if you got nothing from capacity, you might not be shutting down.

THE COURT: Yes, that's true. We went through that.

Yes.

The capacity price that you get is a very nice thing because in effect you're getting it just to be available, and now you've got your full sale where you could make a profit, and I mean you've got a clearing price of 150. The guy that [28] bid 149 is totally covered and he's going to make his 320 on his energy sales, the guy who bid 151 is going to make his 320 on the energy sales. But he's going to be—he's not going to get that 150. And so that's okay. I don't have any problems with understanding it. It's just—it just seemed to me—but if you say it's the way to go, that's the way to go.

It just seems to me the market is not designed to have a bidding on capacity that relates to what they really want or need from capacity.

MR. MEYER: So Your Honor perhaps, I don't want to interrupt a useful colloquy, but if it's useful, I won't interrupt.

But I think it may be helpful to – for Professor Willig to lay out sort of as a foundation how the PJM capacity market framework actually establishes a clearing price and then how that functions to send price signals even to someone, or even allows someone who bids very low to receive the clearing price.

THE COURT: Mr. Meyer, I defer to the way you want to present it. It's very helpful, I'm sure.

MR. MEYER: Just as a shared foundation, it may be useful.

BY MR. MEYER:

Q. I've put on the screen, Professor Willig, demonstrative PD 64. I don't know if this is a useful opportunity for to you [29] just illustrate how this clearing price concept functions to achieve the efficiency goals that these auctions at PJM have?

A. Sure. I think it does. Although it may be our conversation has actually moved beyond this, but let me try anyway.

So this is the start of the dynamic of the supply side auction with particular application to the architecture of the PJM capacity market.

The generators or the potential generators are asked to submit bids, which include the amount of capacity they're offering and also their price.

This MWs and the price is the price per MW day, as I understand it. And the table shows all the bids. So this is obviously an example, and I don't know who these generators are, C doesn't stand for, CPV, for example.

Maybe there is no—there is a C. So these are just abstract.

All these different generators, and there's all their bids, and they're lined up by the size of their price bid. So generator L has the lowest bid at zero. G tied it at zero, three zeroes here, and others are bidding higher prices.

And then over on the right-hand side, the total MWs available at each price. The question is okay, if the price were say $10, how many total MWs would be available at that capacity price?

[30] So it kind of adds up the number of MWs that had been bid in at that price or lower. This is just a tableau.

We could ask the question, all right, suppose we need 8,000 MWs, so let's go down that right-hand column to the row that says 8,000, and it turns out that to get 8,000 MWs, the price is going to have to be $150. Because at 8,000 MWs, we don't get enough total supply given these bids unless the price is as high as $150. But at 150, all of the amounts of MWs bid into the auction do add up to 8,000.

So 150 will be the market clearing price here. At 150, there will be a total offer of 8,000 MWs, and that's what the administrator is trying to secure, having decided that that's what is enough for a load plus reserve in this marketplace looking three years out.

Q. Perhaps we can turn to PD 65?

A. Good, so that's up. So let's look at this. This is a graphic of those same data. So now let's go back to the tableau, generator L remember was bidding in 500 MWs at zero, so on the supply curve, it's labeled supply curve is red, the very first from the left, the first piece of that supply curve is the supply that was offered by generator L, and the vertical height of that supply from L is zero because generator L bid it in at zero.

Likewise, generator G bid in his supply at zero likewise J. But now F starts to move up the supply curve [31] because looking back, F was bidding in at

$10, not at zero. And we move over to generator M. M was bidding $25, and so forth, on up the curve.

It's not a curve. Really it's a jagged broken line, but sometimes it is a curve.

So it moves on up, and then where it hits the vertical line at 8,000, that tells us which are the generators' bids that most cheaply add up to the 8,000.

Let me go back to the different levels of the bids and see why they might make sense at least to me. Let's take a bid at say $60 per MW day, what's generator 0 perhaps thinking about when it comes to the $60? Well, generator 0 is offering in 900 MWs. So that's a big plant. Generator 0 maybe thinking that well it is going to cost me some money to stay available during that year, three years out.

It doesn't cost like building a brand new plant because generation 0 has a facility that's already built, but you know it's going to need some cost. It is going to need the overhead cost of staying available during the year, maybe also needs a little bit of refurbishment to be properly available throughout that year.

So generator 0 thinks well, I'll be motivated on top of my energy margins to keep the plant up and running appropriately if I had an extra $60 per MW day, so that's what I'll bid into the auction.

[32] Generator L has a younger plant perhaps, doesn't need much of anything beyond the energy margins. So generator L is bidding in zero.

And then way up here maybe generator H is thinking I've got a development project on the boards, there's nothing there yet, it would cost me a lot of money to go out and actually commit to its construction, but if the price is high enough, on top of the

energy margins that I expect, if I can get $175 per MW day, then it's worth my while to proceed with the development and I'll commit to it.

So lots of different levels of bids depending upon the character of the development project and its possibilities of these different generators being offered into the auction.

Q. Professor, some of the projects could well be the generators could be plants that are existing in the market without a project in view. They're just generating energy and proceeding along in midlife, as you described it.

How would they think of the capacity market bidding situation?

A. Well, they're thinking that while they would like some more money, and their shareholders and maybe their bankers really need the money to fulfill their expectations, when it comes to the physical decision of keeping the plant up and operating, they don't really need anymore money. They have to keep the bankers okay. Otherwise, they're going to be in legal [33] proceedings.

But nevertheless, this plant doesn't need anything very much more than the energy margins to be kept on and available three years out. And so their bid into the auction is zero, or close to it.

Q. Why does PJM design an auction that rewards all of these generators, all the ones who clear, the same price?

MR. KLEINMAN: I 'm going to object on the grounds it's speculative as to what PJM contends.

THE COURT: Well, I take it to mean from an academic point of view, speaking into an economic

class. It's not that they're actually bidding, it's from an economic model why do we assume that they would do that?

MR. KLEINMAN: Thank you.

THE COURT: So you can answer that question.

THE WITNESS: Thank you.

THE COURT: We didn't hear that he talked to operator 0 at $60. This is why in a professorial way one would assume 0 bid $60.

THE WITNESS: It is a professorial point of view, but it's also a very real phenomenon in the economy, and I wish I invented it, but I would have to be a little more humble if I had.

But this is a great accomplishment of the economics profession instilling from real life business what are the [34] elements that make this kind of procurement efficient. It's been written about in a very theoretical way, but taken up by the community to be made actual and practical in lots of different applications.

So yeah, it's on the blackboard because we teach it, but it's not confined to the blackboard.

Your question, counsel, is about the zero bids and why are people paid even though they're bidding zero?

BY MR. MEYER:

Q. Why does an auction of this sort as used in PJM set a single price that's awarded to everybody who clears even if they bid much less?

A. Right. Well, first of all, imagine the opposite. Suppose that you were considering a brand new development project, and there's a very substantial

cost because you haven't built it yet, and so you bid in that actual cost, maybe it's $180 per MW day, beyond what you need from energy, what you expect to get from energy, and you bid that in, and then perhaps you clear, so you're actually paid current market price.

But then suppose, to follow what you're asking me, the next year you're already committed, or three years later, you have built. Now you're going forward, extra costs are very small, just the overhead cost that His Honor was talking about, or maybe literally zero in terms of what you need beyond the energy margins.

[35] And imagine that the auction architecture said okay, well, thank you for bidding zero, we're going to give you zero.

Well, if that were the design of the auction, then three years earlier, this developer's not going to bid at all. He's going to have no motivation to provide capacity. If the developer thinks I only get this slug of contribution in the first year but nothing afterwards, that's a prescription for no provision of any capacity no matter how important are the markets needs.

So the expectation that this market will continue to operate and operate properly, and continue to pay the one efficient price after you've built, is absolutely essential to the motivation to build plants, which require a big slug of financing at the beginning, but which are not costs that can be retrieved later on except through the market.

If you've got no ability to get your costs back except by selling capacity and energy, then you're not going to build in the first place if you are to be held to zero after that first round of the auction.

Q. We've heard some discussion over the last several days about the fact that the capacity auction in PJM is an auction for a one-year commitment three years in advance, three years from now, or three years from the next auction, that there will be a delivery year in which the capacity price is earned for those who clear.

[36] What you just described sounds like an expectation that goes beyond that period.

A. Yes. The promise is that you will get the clearing price as determined in the auction three years out. But at the same time, there's the commitment you will continue to be paid what are the market clearing prices after that, for the indefinite life of the entire architecture of the auction system.

So it's not like you only get one year's money, you get all the money starting in three years and extending on out afterwards, and gauged by the price at which the market for capacity settles.

So you get the market price, more or less indefinitely, even though the amount of that price, the actual dollars and cents, is only locked in for that one year's time.

Q. Okay. And then how is it that the setting of the price in the auction ensures that the efficient mix of resources is awarded a capacity price return?

A. So if I could refer back to the pictures, let's go back to the PD 65, which was what we had up a moment ago.

Thank you. So if we're shooting for 8,000 MWs, as per the vertical blue line, as what the need is, and if everybody has bid in more or less their cost, and we can talk about the incentives for that in due course,

but if everybody has bid in their cost, then going to the place where the supply curve hits the 8,000 is including all of those sources of [37] capacity that have costs that are the lowest ones possible subject to reaching the 8,000 MW target.

So it's providing the reliability that is determined that is necessary at the least possible cost.

And if anybody whose generation were to the right of the blue line, like Mr. D, for example, if Mr. D were for some reason substituted for Mr. 0, by some mistake or some misfunction of the market, then that would mean that yeah, we'd still have 8,000 MWs, perhaps, but at an unnecessarily high level of cost.

Because these costs are higher than O's costs, and so that would be a mistake for society. And in the long run, the ratepayers would have to pay more money if D were substituted for O.

But allowing the auction to work as it is designed guarantees that the reliability target is met in the least cost possible way.

Q. Perhaps we can advance to plaintiffs' demonstrative 66. It appears to illustrate a different demand curve now.

A. Right. So the way that PJM capacity auction actually works is a slight modification of what I had drawn on PD 65.

Now the blue line slightly more regularly mimics an ordinary demand curve. Ordinary demand curves are not perfectly vertical. There's some price responsiveness to demand so the demand curves have some downward slope. And the [38] actual demand curve that's used in PJM capacity auctions is called the VRR,

looks more like this, than like a vertical line. It still anchored here at the 8,000 if I do it right.

So the VRR demand curve has as its anchor point the amount of load augmented by the amount of reserve that PJM thinks is necessary for reliability, and that's load plus 15 percent, give or take some amount.

And that's the anchor point for the VRR for this demand curve. And then it's given some slope again by PJM's setup.

And then where the supply curve crosses this VRR demand curve is the market clearing price and the market clearing amount of capacity.

So here I've just drawn it so that the clearing price is still 150, the clearing quantity I think is a little bigger than 8,000, and that's the way this market actually works.

This is still a cartoon. It's the blackboard version. It's oversimplified for several reasons. But maybe most importantly for subsequent conversation, what is actually needed is not just monolithic across all of PJM, but there's certain locational issues about the amount of capacity that is needed in different parts, regionally of PJM, and that's built into the operations of the auction in a complex way, which we'll come back to, I think.

Q. I suspect we will back to that in a short while.

[39] Now, with that foundation—

THE COURT: All right. Let me ask, is the intention of the blue line that starts at let's say 260, would that have a slight downward slope rather than a perfectly horizontal?

THE WITNESS: Yes. There is actually a horizontal segment, but in the expectation it will never become relevant, it's just the way to complete the picture.

The action points are the points more or less around the point, the pivot point, the calibration point.

THE COURT: 7,500?

THE WITNESS: Or 8,000 and a little more.

THE COURT: Well, on this chart, at about how many, let's say 7500, the willingness to pay starts to drop?

THE WITNESS: Oh, yes, yes.

THE COURT: I mean, that's where—i mean, I follow the demand curve and obviously, the probably if there was only 500 MW available that the actual price would be astronomical because of the need and so on.

THE WITNESS: Yes.

THE COURT: I understand. I mean, it really wouldn't be horizontal like that, but that's totally academic, you know. Only 1 MW of electricity available in PJM, the price for that MW's going to be off the charts.

THE WITNESS: Off the charts is right.

THE COURT: Right. This illustrates that at a [40] certain point, the supply, the demand becomes price sensitive. Below a certain level, it's not price sensitive, because it's totally necessary, and it's going to have to be—going to have to be purchased whatever the price for this year at least.

THE WITNESS: I think that's fair. The portion of the VRR that's thought to be practically applicable is the portion that starts at the calibration point, which is the reserve margin that's felt to be necessary at the time of the expected load, and that's calibrated a price, which is given by CONE or NetCONE, which I know you asked about yesterday and the day before, the Cost Of New Entry, which is administratively determined by PJM.

That's the calibration point, the pivot point of this demand curve. And that's given some slope on the thought well, you know, if the price is attractive enough, then we can go a little higher in terms of how much capacity is secured a little bit more. And there's even some give on the other side, that if the price is higher than we would otherwise expect, then in fact we can give up a little bit of that reserve margin at least for this one auction.

That's why there is some slope just to give some price sensitivity to the total amount of capacity that is secure.

BY MR. MEYER:

Q. Okay. So with that foundation, I'd like you to describe [41] the contract differences, the pricing contract at issue in this case sets a price. Perhaps we can show plaintiffs' demonstrative 19.

I'm sorry. Could you take that down for a second? It has the magic number. I didn't realize that, I apologize. It's down.

Can you cover that? Just the number?

A. Oh, I think it's 33.

Q. Plaintiffs' demonstrative 19.

A. Oh, yes, I'm in the wrong spot here. It is 19.

Q. I don't know, Professor Willig, if this will be easy for you to talk about without the magic number, but let's give it a try.

A. Okay.

Q. Showing you a chart that exhibits payments under the pricing contract. Could you describe for the Court how from your economic perspective the pricing contract for differences establishes a price?

A. Sure. Does His Honor have the same picture I have with the numbers on it? I shouldn't say them out loud.

THE COURT: Actually, there's a number on mine. We're going to ignore the number. I don't think the exact number makes any difference.

THE WITNESS: No, really it doesn't, not to this chart. But it's easier to talk about with numbers, that's all.

[42] Okay. So let's look at the capacity market flows here in this picture. Up top is CPV. At the bottom is the set of EDCs involved, BGE, Pepco, Delmarva Power. And if CPV performs—if under this contract, if it does actually succeed in constructing its generation, and if it does, if in fact it does properly clear the capacity market, if it performs, then certain money flows, come about, for CPV.

And what happens if it does perform is that it winds up on that with respect to the capacity markets with 'the magic number per MW day of that capacity's availability.

So the magic number is actually the price that it receives for providing the capacity subject to those

performance requirements. If it performs, it gets the magic number per MW day for the capacity it makes available.

How that number actually comes about is governed by these arrows, which I guess are a little bit busy and a little bit confusing, but the way it works is that for the performance, the provision of that capacity availability, CPV is entitled to a cash flow from PJM equal to the RPM clearing price. But then at the same time, it's giving that back to the EDCs.

THE COURT: Well, Professor, why don't we just take a round number of 500, and just so we can be talking about numbers. Everybody understands that's not the number, but at least I think it will make the talk a little more clear. So [43] just use 500, which is just out of the blue here.

THE WITNESS: Okay. That's great.

THE COURT: All right.

THE WITNESS: So let's say the magic number is 500, which it's not, and that sounds like blackboard talk now.

And suppose that the RPM clearing price is $150, then what happens to CPV is it gets $150 from the capacity market, and then it gets the rest of the way to the 500 from the EDCs.

That's what makes a contract for differences, because then the cash flow on the capacity side from the EDCs is the 500 less the 150, so it's the difference between the two. And that's why it's called a contract for differences in part.

THE COURT: Well, that would be 350.

THE WITNESS: Yes, sir.

THE COURT: As I understood from Mr. Knight's testimony, the 500 is the guarantee, which is a total of the capacity price plus the profit on the energy market. So it's not just the capacity market. Although, you know, I'm perfectly comfortable to say if we're going to give the idea that for this year the projected energy market price, energy profit's going to be 320, just to take that as a number.

So but at the so-called magic number, the 500, is to assure them revenue of 500 as a total of energy profit plus the capacity price and the ancillary services, which is supposed to be 18, that's on the side, that's a game they're playing [44] independent of all of this.

So it wouldn't just be the capacity. The capacity market here cleared at 150, and the energy profit was 320, they would get an extra 30 bucks from the CfD? They wouldn't get 350 from the CfD, they'd get an extra 30?

Is that an accurate—let me ask counsel, isn't that an accurate description of what happens?

THE WITNESS: Well, ask me.

THE COURT: I mean, isn't that what—I'm just going to ask Mr. Eisenstat, isn't that what Mr. Knight said? Yeah, that's what he said. So everything's here in principle except for this particular example, the capacity part of the chart is 150 plus an extra 30.

THE WITNESS: If you'll look at the chart, we try to make the chart include both energy and capacity so that it wouldn't give a misleading bottom line for the reasons that you're suggesting.

I was just talking to the right-hand side of it for now. You're quite right, at the same time the left-hand

side is going on. And you're quite right, in my view, also that the $500 bottom line, magic number, in terms of function from the point of view of CPV, is that it replaces what the capacity market would be paying as the RPM clearing price, and it also replaces margins that would have otherwise been earned on the energy side.

[45] THE COURT: Yes. But remember earlier, this is why we got to the earlier conversation that because I think we're going to get into the substance of what you're talking about, it is very helpful to talk about numbers. We're making the assumption that for the year we're looking at, the energy profit's going to be 320. The energy profit would be 320 whether they cleared or they didn't.

I understand if they don't clear, they don't get paid under the contract. But nevertheless, it's in this particular year, the action from the CfD is to increase the capacity, what they get from capacity by $30 on our little examples.

I recognize, I mean at least in terms of interference with—since the CfD does not, as I understand it, affect the energy market because their clearing doesn't affect prices on the energy market, as I understand it, the concern is the effect on the capacity market. And in this case, for this particular year, that happens to be a $30 difference?

THE WITNESS: Here, the magic number in the year that we're talking about, the magic number, the 500 bucks, replaces the 150, and also replaces the 320. I think that's what you're pointing out.

THE COURT: I understand. I understand.

THE WITNESS: I'm just agreeing with you.

THE COURT: Which it does. But it doesn't affect the 320. The 320 would be the same with or without the CfD?

[46] THE WITNESS: Well, I agree with that except, and maybe importantly, that if the existence of the plant, it depends upon the fact that it was brought in under the CfD. And—

THE COURT: I thought your opinion was, your opinion should be whatever it is, but I thought your opinion was—maybe I'm wrong—was that the CfD affects the capacity market and capacity price.

If I'm wrong, if you say that it affects both, that's fine. I just didn't want—so I think I'm understanding, you're saying that the CfD affects both market prices?

THE WITNESS: Well, in different ways, and I think it's worthwhile to hear what differences there are.

Because here the CfD produces one bottom line, and interestingly, that bottom line stays the same every year during the pendency of that contract. It's always $500 in our example. Even as the 150 capacity market clearing price might change over time and even as energy prices change over time.

So the magic number is replacing the workings of the market on the energy side and also on the capacity side. But in different ways.

But still, it is the replacement for the return to CPV from both sides.

THE COURT: Is this an accurate understanding, it affects the energy market because we're putting in an extra 661 [47] MWs, which is a supply issue, on the energy market, I understand that.

And in the capacity market, it has an effect because of its relationship to the bidding system?

THE WITNESS: Yes. And to the extent it brought in a plant, which would otherwise perhaps not have been constructed, then that affects market clearing prices in both markets.

THE COURT: Well, okay. So I think that I understand, and that your opinion relates to both markets, and there may be—there is a difference.

With that counsel, you can proceed, please.

MR. MEYER: Thank you, Your Honor.

BY MR. MEYER:

Q. So you've talked about both sides of this equation, and perhaps if you could just walk us through why you regard this set of payments as a price, that's being provided to CPV?

A. Yes. This is a price. Because it is conditional on performance, it's only paid if there is performance by CPV or whomever would be the recipient of this arrangement under state auspices.

If CPV does not build, then it doesn't get this money. If CPV were not providing the full capacity availability in any year, it would not be earning the price, the magic number price of 500 per MW hour day. Excuse me. MW day.

[48] This is a price. It's money for performance, which is what price is all about.

Q. And the performance, you've mentioned coming into the market, the offering into the capacity market, and so forth, is the performance linked to the sales that are occurring of energy and capacity into PJM?

A. Yes, it is. And I should say also the clearing, I think I left that out just a moment ago. So it's pricing. It's compensation for performance, and performance has those different elements to it, the actual provision of capacity, the clearing of the capacity market, and also on the energy side.

There's a complex formula, but the amount of energy involved does affect what the payment is.

Q. And you've touched on this, but does the fact that the two sides of this picture are netted out in the contract affect your conclusion about the characteristics of this as a price?

A. No, not at all. It just means you've got to deal with complicated-looking diagrams like this and worse ones than I've created in the past that are even more confusing.

In a way, the complication goes to the name contract for differences, because to be a contract for differences means there's going to be some subtraction involved in figuring out what the cash flows are that matter.

But economically, and I think from the business perspective, also, having listened to the witnesses from CPV, [49] seems to me from the perspective of CPV, the bottom line is the magic number, that's what they're getting if they perform. The fact that it comes from this source and that source with a difference here and a little complexity to the cash flow there, their business decision-making, I think we heard this clearly, and this is certainly right as a matter of economics, depends upon the size of the bottom line, which they compare to their costs of achieving the performance that that bottom line rewards.

Q. When you say you heard that their business decision-making depends on the size of the bottom line, what were you referring to?

A. There was a slide that I think Mr. Egan or maybe it was Mr. Knight, maybe both of them, were discussing yesterday. It was X because the name of the magic number yesterday was X. And then there was a 15 or 18 that were the net revenues from the sale of ancillary services that everybody wanted to ignore, which makes sense to me.

THE COURT: Yes, that's defense demonstrative 23.

MR. MEYER: Thank you, Your Honor. I was looking for it myself.

THE COURT: If you want to put 500 in for X, but that's very helpful.

BY MR. MEYER:

Q. Professor Willig, is your understanding the way this was [50] constructed that X would be 500 in the example we've been discussing?

A. Yeah. X is the magic number there, I believe which we used 500 to represent for the last 15 minutes or so.

And I think I heard the witnesses say that look, at the end of the day, under the contract, they're looking to X, plus either with or without the additional $18 as what they'd be expecting to get as contributions to their—I think they used the phrase revenue need or net revenue need to support the financing.

So that was the bottom line in terms of the availability of proceeds forward to support the construction and the further development of the project. But that was

the bottom line that they needed, and they were hoping if they could enter into an attractive enough such contract, that X would be enough to cover their revenue need. So that was the bottom line.

The fact that it emerged from some pluses and minuses of what would otherwise be their revenues from PJM energy and capacity markets didn't matter at all, it seemed, it was the bottom line that mattered after the differences had their effect. And on that picture it was X. In our example, it's 500.

Q. We heard discussion yesterday, perhaps we can go back to plaintiffs' demonstrative 19, we heard discussion yesterday [51] about from—I'm sorry, I thought it had been masked.

It's off.

Again, we heard discussion from Mr. Knight, I believe, about the fact that the differences can end up meaning that CPV owes more money to the EDCs than it gets back from the EDCs in the netting process?

A. Yes.

Q. And suppose it's theoretically possible that that could happen under certain circumstances over the life of the contract; isn't that right?

A. Absolutely.

Q. And does the fact that CPV—the net price to CPV, net payment to CPV is a negative payment affect the nature of the contract price as a price?

A. I think the answer is no. But—

Q. Sorry about that.

A. Let me explain because I'm not sure how many no's or yeses you had in there.

Regardless of which component is bigger or smaller in any one year, and regardless, therefore, of which way the various cash flow elements involved in this whole satisfaction of this contract, which way they go in any one year regardless of all that, bottom line to CPV in any year is still the magic number per MW day.

And so even though they might be paying some money or [52] receiving some money from here or from there, the bottom line is the magic number per MW day.

And the economic logic certainly suggests that that is the right answer. The arithmetic shows that's the right answer, and I believe the testimony agreed with that yesterday.

Q. We've been going about 90 minutes, Professor Willig, would now be a good time for a short break?

A. It would be, yes.

(Recess.)

THE COURT: Okay.

MR. MEYER: While the witness returns, Your Honor, I just wanted to note for the record that on plaintiff's demonstrative 19, our artisans over here have substituted the $500 price that you were referring to.

THE COURT: Okay.

MR. MEYER: Using the illustrative magic number.

THE COURT: All right.

BY MR. MEYER:

Q. So Professor Willig, I think if I may—if I may summarize what I've taken away from your testimony so far—

THE COURT: In the future, just put an asterisk $500 is an arbitrary assumption, so in the future, so the record doesn't make it look like we're saying where it is.

MR. MEYER: We'll add that, Your Honor, thank you.

BY MR. MEYER:

[53] Q. If I may summarize what I take away from your testimony so far, on your first principal conclusion it is that the pricing contract in this case establishes a price will be received by CPV in connection with its sales of energy and capacity?

A. Yes.

Q. And how do those prices set by the pricing contract relate to the prices that CPV will receive in the market for sales to PJM?

A. It's a different price. But I'd like to for the record, a further thought amend what I just assented to a moment ago in your articulation.

Not only does the price in contract set a price, but it's a price, it's the price that replaces the market price.

Q. Thank you for that.

So I'd like to put on the screen plaintiffs' demonstrative 33, and in obedience to the protocol of the day, we have whited out on the Y axis, and with permission of defendants, or consent of defendants, show a chart that has the dollars per MW day on the Y axis, but the numbers are blanked out, and delivery years on the X axis.

Perhaps Professor Willig, I could ask you to explain what this chart is depicting?

A. Sure. So the lowest line, which I think is intended to be red, at least in my version, with little squares on it, is at the level of the market-based capacity price per MW day of [54] capacity. It is the price for capacity from the PJM capacity auction. So that's the red line.

It's going forward, so this is a projection, and this is a projection that's due to Boston Pacific, the consulting firm, who as I recall was engaged by the PSC, PSC Maryland, to help administer the RFP process and make its own decisions.

And in the paperwork that it released to support its own decision-making, it had various projections of elements of the market, and this is part of what those projections were.

So this is not my projection. This comes from Boston Pacific's work.

The relatively level upper line, which is more or less in blue, is the magic number as it is expected under the intended contract to be affected by time, and subject to a slightly important, but not very important, escalation clause.

And so its movement across the picture is not because anything anybody is doing, it's simply because of the expected rate of inflation and the way the escalation clause in the suggested contract affects the level of the magic number, as it were.

So that's the magic number. It's quite different, as you can see, from the red line, which is the expected clearing price for PJM's capacity auction.

It looks very different on the picture. So that's to make the point that those numbers are very different, at least [55] as given by this picture.

And then the line that moves around, I can't really see the color on my own slide, but it's got little triangles on it, and this is the market-based annual compensation per KW day of capacity. It's averaged over the year, but we're still in units of MW day returns.

And that curve adds up, again, under the projections of Boston Pacific what would have been the returns to CPV per MW day, including both energy and capacity payments.

So His Honor was talking about a 380 number, I believe, Your Honor, from some previous example slides as profits from the energy side.

THE COURT: Estimated 320.

THE WITNESS: 320, thank you. So that would include at least in this picture $150 per MW day of capacity in the beginning, 2015, 2016, the 150 plus 150 put on that same scale as returned from the energy side.

And that's where that line with all the triangles begins in 2015, 2016, well below the magic number, which is meant to replace it, as we've been discussing.

And then according to the projection of Boston Pacific, that number, with the market-based alternative, moves around, is rising at different rates of time. It starts falling off toward the end. The crossing point is some five or six years out, according to this projection.

[56] Q. So let me ask you just a few questions about this chart.

Boston Pacific appears to have used a constant figure for its assessment of potential capacity revenues from the market, the red line, correct?

A. Yes.

Q. If the red line turned out to be not constant but variable, varying with market clearing prices in PJM over time, what would that do to the green line?

A. That would make the green line move around correspondingly.

Q. And if the level of energy prices was less than or more than what was being projected by Boston Pacific, what effect would that have?

A. Well, the energy margin is part of what's in the green line, the line of the triangles. And so – and indeed as the expected energy performance side of the market changes, that's part of why this line has some movement to it in this picture. And if there were other changes beyond, more in addition to those projected, that would cause additional movements of the green line.

Q. And do any of the movements that we've discussed at the green line or red line affect the blue line?

A. No. The blue line, the magic number is set. It doesn't respond to market forces. It doesn't equal market prices at the beginning. It's not expected to. And it's not influenced by any subsequent developments in the marketplace.

[57] Q. Thank you.

So let me ask you this question about the price that we've been discussing this morning set by the pricing contract. There's been discussion in this case about the

fact that the pricing contract is just a financial transaction or just a hedge. What is your view on that?

And perhaps I can put plaintiffs' demonstrative 73 on the board.

A. Thank you. At the risk of repeating Econ 1 material, from the point of view of economics, and I think logic, but it takes thinking about it, from a logical point of view, price is not just receipt or payment of money. Price has to do with influence on economic market or otherwise has to do with influence on activity. It's money for doing something. It's performance-based.

So looking at those three bullet points on the slide, price is the amount received by a seller for selling. It's for the object or the service that is transferred. It's not just, you know, you give your kids money because they're your kids. Well, it doesn't influence their behavior any more. If they had a choice about being born, it might have influenced that, but they didn't. I know my daughter was just sending me an e-mail asking for money, I couldn't call it a price. Maybe it's the price of fatherhood, but that decision was long done.

It's not just a transfer. It's a price for an [58] activity. And when it comes to the amount received by the seller, it's the compensation for the sale for the decision to supply and to implement that decision.

So it's money for something.

That's at the point of sale. Price also has—and this is the second bullet—another function, which is part of what makes it a price. Instead of just a transfer of money, it gives a return to the investment to the

capital that lay behind the supply of the object or of the service that we're talking about.

And so the price goes to compensate the original investment in the capital that was necessary to supply the product and the amount of that price or it's anticipated level influences the decisions about whether or not to make the investment in the first place.

It influences the investment activity.

So again not just money, but money for performance, both in terms of the original investment and also in the subsequent supply activity.

Also the price is the amount paid by the customer for the receipt of the service or object. And in some circumstances, the amount that the customer has to pay influences the customer's decision about whether or not to acquire the product or the service.

Q. Does it matter here that the sales that CPV is making are [59] to PJM rather than directly to the EDCs who have contracted with it?

A. From the point of view of the first two bullets, the supply activity, its supply of capacity together with energy to which this flow of compensation under the pricing contract is linked, it's related, it is conditional on performance, so it is the price as experienced by CPV.

Q. And what about the third point?

A. The third point is less clear here, and less influential, because, well, it's not clear whose behavior could be influenced by the need to pay under the order of the Public Service Commission, as I understand it, without being the warrantor of the legalities, which is

not something I can do, but the EDCs have to pay, it seems, under the order of the PSC.

And so it's not like they have any discretion over their activities in this regard. Depending upon how they regard the appropriateness of the pricing, they have to do it by state order, as I understand it.

So there's no discretion here to make the third bullet either work or not work.

Q. I see. Now, does the fact that this pricing contract may perform a function of helping risk on the part of CPV affect your conclusions?

A. Not at all. What makes the price a price is that it's compensation for performance, and that's why it helps to [60] influence or govern activities by those who have a choice.

But what currency it's in or what fluctuations it has, or how much of a side effect on hedging it has, none of that changes the fact that a price is compensation for performance.

Q. I'd like to turn our attention to the second of your principal conclusions.

THE COURT: Could we go back to demo 33? The chart with the red and the blue and green lines?

Okay. That's not—

MR. MEYER: I think it's on your screen.

THE COURT: I don't know what the function of this chart was presented by Boston Pacific, but—and I just want to see, it doesn't seem terribly meaningful, it gets confusing.

First of all, if this is of course a projection, and the projection is that the clearing price, which is the red line, correct? The red line is the clearing price?

THE WITNESS: Yes.

THE COURT: That's going to stay the same for 20 years? It's not—I mean, as we understand, it's going to vary all over the place?

THE WITNESS: Probably will, yes, Your Honor.

THE COURT: So I don't know what we're doing with that.

The second thing is that the difference, the Delta [61] between the red and the green line each year is the energy margin, correct?

THE WITNESS: Yes.

THE COURT: And what are—there's some reason what Boston Pacific has is the energy margin wildly fluctuating and you know tripling virtually from the first year until it gets to ten years out, and so that again whatever the relationship is to the blue line, the blue line I assume to be the 500, which because of inflation, et cetera, may go up to 510, but that variation, we don't care about.

So I'm not knowing what they're telling me. First of all, for what use are they making of the fact that you're going to have? For some reason, they're going to assure themselves that there's going to be this three times energy profit ten years out. And we have this wild variation on the red line.

I mean, it just looks, from what they're saying, that at least on this chart, the CPV's going to end up paying back at, least it's just using these numbers, what does this chart—it's illustrative, yes, it shows me

that the combination of the green line, which I guess is the combination payment is going to vary, and it can be higher or lower.

But what else does it tell me?

THE WITNESS: The point that I wanted to make today on the basis of this chart, and I believe in my report, also, is just the simplest point, that these prices—not only did [62] the price, the magic number price that comes from the pricing contract, the contract differences, not only does it arise through an entirely different process, as we discussed already today, but at the end of the day, it is different.

Numerically, it's different. It's not like oh, there's two different processes of price determination, and they sound different, but never mind, at the end, we wind up the same. For practical purposes, that's not the case. That's the intent of showing you this chart.

And this chart comes from Boston Pacific, who were the consultants to the PSC, so it's their work that's making that point.

THE COURT: All right. I doubt that there's any debate about that. I understand this chart is to me is not—I think I've said it, it's fairly obvious that the red line should vary, which would mean that the green line will swing along with the red line, because the green line is merely the red number plus the assumed energy profit margin so that you're going have an even wilder variation.

But whatever it is, it's not going to be the blue line?

THE WITNESS: I think that's really the point.

THE COURT: That's fine. Okay. Thank you.

BY MR. MEYER:

Q. So Professor Willig, turning your attention to the second [63] of your primary conclusions relating to the Public Service orders and the pricing contracts interference with FERC's policy goals, what FERC policy goals do you regard as being interfered with here?

A. Well, I think, put very concisely, the FERC policy goal that I had in mind was to see to the provision of reliable power at the least possible cost. The least practical cost.

I think that's a summary of what could be a lot of verbiage describing the policy goals of the FERC.

Q. We put up on the screen plaintiffs' demonstrative 86. Showing what is a quotation from a publication by PJM entitled "A review of generation compensation and cost elements in the PJM markets."

And I believe that there is a second slide that continues this quotation to its conclusion. Under the heading "Rationale for the RPM capacity market."

Could you describe what this is depicting?

A. Well, the last sentence on this slide is what I was just trying to paraphrase, or vice versa. And I do like that articulation. Certainly in short getting the wholesale price incentives right is fundamental to maintaining reliability at the lowest cost.

So what that sentence is highlighting is that well, the underlying goal of the FERC is what I was suggesting, but that FERC moreover has gone on from that fundamental level of [64] goal to say in many different fora and over time for quite a while, that its view is that it's important to inject as much competition as

possible into the wholesale power market for that purpose.

That injecting competition and using pricing consistent with competition as a set of signals to guide allocation decisions and investment decisions, that entire architecture for the wholesale market is FERC's policy choice in order to accomplish the underlying goal of maintaining reliability at the lowest possible cost for society.

This goes on to break that down a little bit more I think in an appropriate way; namely, part of the decision-making that the market has to accomplish, or regulation has to accomplish, is to choose the mix of resources and where to place them and when to place them and what kinds of resources ought to be put into place.

And where I read this as saying that all of those discussions, which always have to be made, or made in ways that are consistent with the market, and with meeting reliability needs at the lowest possible cost, is the choice of how it is to organize the wholesale marketplace.

It says that if the incentives are not right because prices and revenue streams are not sufficient to support the right mix of resources or attract new ones, then there will be suffering by the marketplace. Reliability will suffer and cost [65] will be unnecessarily high and risks to the public will result. So this is a strong statement to me of FERC's underlying goal and FERC's decision to attain that goal as best as possible through the use of market mechanisms and the use of competition in the wholesale marketplace.

Q. And how is it that the wholesale marketplace that PJM seeks to implement these goals?

A. Well, there's a variety of levels of policymaking. The whole idea of PJM in a way is an early step in terms of the hierarchy of decisions along that path making wholesale electric power marketplace interstate and making it have a relatively broad scope, certainly compared to a single state, including as many as 13 states in a single RTO.

It's actually very important, I think, in terms of the steps that have been taken in moving toward the accomplishment of the goal, because at least economists understand that listening to engineers, not being engineers, but listening to engineers, there's real economies of putting together a broader geography and putting together more load arriving from different places into a single operating market, and doing so, actually lowers total costs if the management of the load and the resources within that footprint is done competitively and efficiently.

So what is PJM, first of all, is a step in the direction of listening to the admonitions of this sort of [66] policy statement.

And then moving from the broadest down to what we've been talking about today, the PJM decisions about implementing markets auctions for energy and for capacity is a very important, almost a central step in adopting a mechanism that accomplishes the mix of resources, the choice of place, choice of timing, the choice of technology for making those decisions that society has to make in a way that adds up to providing reliable power at the lowest possible cost.

Q. And how does that principle get reflected in choices about what kinds of resources to select?

A. Yeah. I mean, it's crucial if the goal is reliability at the lowest possible cost to discriminate only on the

basis of .cost. Not to discriminate on the basis of location, except inasmuch as that location might be reflected in the cost difference.

And not discriminate on the basis of even timing, except inasmuch as timing influences cost.

Not discriminate on the basis of choice of technology, except inasmuch as that bears on cost.

Not to discriminate on the basis of brand new construction, as compared to some sort of an uprate existing resources.

Not to discriminate on the basis of existing technology and existing resources that may be ready for [67] retirement or not, as compared to an uprate of an existing plant or the construction of a new plant, but rather to keep the eyes of the mechanism affixed on cost implications rather than on any of these other characteristics.

Non discrimination would be the overriding thought.

Q. In your list of ways in which discrimination may occur, you mentioned discrimination based on timing. Would you explain what you mean by that?

A. Yeah. From the point of view of providing reliable power at the least possible cost, it matters when investment dollars are spent. It may very well be that it makes more sense to wait a few years to make a major capital investment rather than making it earlier from the point of view of reliable provision of power at the least possible cost.

It's more expensive to build earlier than it is to build later levels of cost constant, because if the money is spent earlier, then the money is being denied its other uses. Money has time value. Better to have money in

your pocket today than to have a promise of getting it at some point in the future.

And so the timing of capital investment is a very important part of cost efficiency.

Q. So perhaps we can—I can ask you to illustrate again how this principle of non discrimination works in the context of PJM markets, would it be useful to refer to plaintiffs' [68] demonstrative 66, the chart of the supply curve?

A. Yes. So by the operation of this auction mechanism, no question is asked of L, G, J, E, 0, all these potential sources of capacity.

No question is asked about are you new or old? Or are you an uprate? Or are you an owner of a resource who was thinking about of avoiding retirement?

Just the question of are you willing to commit with some escape hatches, because there's ways to get out, but will you commit subject to that, to the provision of capacity three years out?

And what would it cost you? What kind of price do you need in order to be willing to meet that commitment, irrespective of from the point of view of this chart—remind me to come back to this—irrespective of like, irrespective of what kind of technology you intend to use, irrespective of whether you're thinking about retirement or not, irrespective of whether it's an uprate or not.

Q. Professor Willig, how could the Maryland orders at issue in this case address or approach this issue of selection?

A. The Maryland order is particular and selective, and you might say discriminatory, but that's not necessarily pejorative in this context. It's just being

efficient about what the capacity has to be to be awarded the pricing contract.

And we've heard the elements of that selectivity [69] discussed many times this week. But it has to be within SWMAAC, and it has to be in a given year, and it has to be gas-fired. It has to be combined cycle. Remind me what others?

Q. Does it have to be new?

A. It has to be new. Of course. It has to be new construction. Thank you.

And these are all elements to which the qualification for the PJM capacity auction, these are elements to which no discrimination applies in the PJM auction. These are elements of discrimination that do not necessarily add up to qualification as part of the least cost provision of reliable power; namely, FERC's policy goal and also PJM's as expressed on the previous slide.

But whatever the original motive, the pricing contract has these particularly selective stipulations.

Q. How does that difference between the selection characteristics of discrimination, as you put it, interfere with achieving FERC's goals?

A. In many ways. First and foremost, and most directly, again, not to personalize this, but I suppose it is personal CPV being the party to this possible contract at this time.

CPV, if they come to terms, not over pricing but over some of the features of the contract, and indeed go ahead, which I guess we don't really know whether that is the case or [70] not, from the testimony yesterday, but if they do, because they're motivated to under the pricing contract, that will be the unit of capacity that is provided and actually built.

And if the PJM market process and if the goal of efficiency as articulated by the FERC would not have included that plant, then first and foremost, it's the wrong outcome for the policy purposes and goals of the FERC.

And second, in the same breath, it's not what would have resulted from the PJM auction process.

Now, I don't know, we don't know whether the plant is going to happen. We don't know whether in some other world it would have happened, but it's perfectly clear as a matter of policy and architecture that the process of determining of whether that plant is built or not is not the same process that is consistent with the FERC policy goals.

Q. And how does the PJM auction process determine whether that plant is going to be built or not?

A. The PJM auction process – good. We've got the right demonstrative up. Thank you.

Chooses for the provision of capacity for the clearing and for the promise of the payment of the market clearing price, those sources of potential capacity who are the lowest bidders up to the amount that's needed.

So L, G, J and so forth on up to potential generator or source of capacity B are the ones who through this process [71] are committing to provide capacity three years out. They're the ones who will be rewarded for it by the capacity payment not only in that one year, but thereafter based on whether they're the lowest cost bidders up to the level of total capacity that's needed.

Q. Professor Willig, what effect does the participation in an auction by a generator like CPV, with the pricing contract of this sort that we've been discussing

have on the outcome of the auction and other participants in the auction?

A. So we don't have the magic of the dancing slides, which is good, because I never managed that well, but in our mind's eye, imagine that there is another piece of capacity that's going to be implemented, and say where one auction late and so it's a done deal, it's going to bid in at zero or very low, it's going to move the entire red curve over by the size of that capacity. I think the number is 661 sticks in my mind.

But whatever that number is, the capacity of that project, once it's committed to, in all subsequent auctions, it slides the supply curve over to the right by that amount of capacity.

And now here's the tricky part, but I think you can do it, if you imagine that red curve sliding over to the right, what is the place where that new red curve intersects the VRR, the blue demand curve? It now intersects at a lower price point.

[72] So that's just the graphics behind the one liner that says well, if there's more supply in a market and no change to demand, the price will be driven down. And that's of course generally right.

But here that's true in the PJM capacity market, that the additional capacity in this market that is brought about through the CPV deal under the pricing contract will slide over the supply curve in that very same year but also in subsequent years. And so the price will tend to be lower.

Moreover, and this is the obvious follow-on, but it's very important to separate it, I think, is not only will that actually happen, but the market participants will expect that to happen when they're thinking about the

prospects going forward, for what the prices will be over the lives of their projects, that come from the PJM capacity market, they'll recognize that this additional plant is not only going to drop price right now for the three-year payments, but the entire expected stream of payments over the next 10, 20 years, will be that much lower, also.

And so there will be diminished expectations to other potential developers for what they would get from the capacity market as a result of the build of the CPV plant.

Q. So if you're looking – is the point that if you're looking ahead to next year or the year after, you'd expect to see those changed expectations alter outcomes?

[73] A. Yes. It's been so confusing, because the promised price is just that one year, three years out. But any developer understands that the project which succeeds and is built is going to continue and earn returns from the capacity market for the life of the plant.

And so expectations of what is to be the market clearing price, not just in three years paid out, but subsequently, very much affects the incentives of new developers who are making their development decision right now.

And that's true about developers in Maryland. And it's true about developers outside of Maryland as well throughout the entire PJM marketplace.

And if expectations about subsequent prices are that they're going to be lower, then developers will be deterred from committing their money to new plants, because their expected returns will be compressed and

that much lowered by those changed expectations. That means less development at the end of the day.

Q. And what consequence would that have with respect to the goals that FERC and PJM markets have?

A. So, for example, suppose that one of the developers, potential developers, who would be discouraged by those lowered price expectations had a more efficient plan for building capacity as far as the entire needs of PJM were concerned, a better plant as it were than the CPV project.

[74] And you know, again, it's not personal. I have no idea whether the CPV project is the greatest thing or not. We're talking about the policy toward the way this marketplace works and it's supposed to work.

But in general, there could well be a more efficient provider of capacity ready to build this year, next year, soon enough, who would be deterred from building because of the State's procurement policy and because of the embodiment of that policy in at the CPV project most directly.

Q. And is it conceivable that if such a project that could exist could be anywhere within PJM?

A. Absolutely. Imagine that the next or the most efficient project, but the next one up, could be a project that didn't meet the requirements of the RFP governed by the PSC, I suppose it wasn't going to be in SWMAAC, this other project, and suppose this other project is actually more efficient, lowered cost, more capacity, better location from the point of view of the entire functioning of what's needed to keep electricity reliable inside PJM.

But that potential developer looks at where the supply curve is going with the CPV plant in it instead of not in it, and it says, no, no, this is not an economic project, not a compensatory project for us anymore because of the lowered expectations about what are to be the clearing prices from the PJM capacity auction.

[75] So we wind up with the CPV plant and without this other plant, even though the other plant would have been more efficient than the CPV plant because of the State program, the State program making its choice of the CPV plan based on the criteria of the State program instead of on the non discriminatory criteria that are consistent with the policy goals of FERC.

Q. We've heard CPV and the State of Maryland express at times in this case, this week, that the pricing signals sent by the PJM markets are useless.

Have you considered that in connection with your evaluation of the impacts you just described?

A. Yes. The word—I'm not one to judge the credibility of other witnesses' statements, and I don't mean to in any way step on the fact-finder's responsibilities and try to displace them.

From the economic point of view, the expectation of returns from the capacity auction can be significant, can be an important part of the expectations of long run viability of a project. And to say they're useless just doesn't fit within that framework of economic logic.

It does make sense to say well, just one year short of payment, well, it's just one year, what's going to happen next?

But what happens next is that the auction will be run [76] again. Again, there will be a new market clearing price determined by it, and the potential builder will be expecting to receive it, if the project goes forward, that return from the next auction and next auction on out through the life of the project.

If there's—even though prices are not preset, there could be marketplace events that will tend to raise them or to lower them as a group.

And indeed we're talking about here is a state policy and its immediate implementation through the CPV plant that first and foremost drop those expected payments.

Even though you can't predict an exact level of any one of those payments, you can predict that an additional important plant is going to drive down future prices throughout the entire life of your project.

Q. So are you saying that this altered set of expectations has an effect on an investor even if the price levels that are actually realized going forward are somewhat volatile?

A. Yes. It can be volatile going off into the future, but let's come back to that level of volatility. But even if they are volatile, which I think they have to be accepted that they are likely to be somewhat volatile, nevertheless, it's clear that putting in more capacity through a state-oriented program, which may lead to an inefficient choice of capacity resource, has a one-way directional effect on the entire future of course [77] with all of the prices, namely downward.

Q. You've wanted to come back to the level of volatility.

A. Yes. Thank you.

You asked me earlier about the impacts of the program and how they bear on the achievement of FERC's policy goals, and I said well, the most direct and first implication has to do with the building of the CPV plant.

And then I just went on to well, that's going to have a one-way effect on expectations of future prices pushing them down from the capacity market.

But now the next level, and I think this is of comparable importance, it's hard to see which one is more important, but the existence of state programs of this kind, first of all, means that there may very well be additional capacity constructed, again, under discriminating or discriminatory criteria.

Construction projects that would not otherwise have been built except for the promotional activities of Maryland, and that, too, is yet more pressure on the entire future range of market clearing prices from the PJM auction.

Also downward.

Q. I want to make sure I understand. Are you suggesting that market participants might perceive that if Maryland has done it once, Maryland or other states could continue such programs?

A. Absolutely. So now we're talking not just about CPV, but [78] about the policy.

And to some extent, I think that policy will be shaped by what happens here about such state programs generally, in Maryland and perhaps elsewhere as well. And that market participants, developers thinking about the possibilities of committing their financing to a new generation project within PJM would have to be thinking about what is the likelihood

that there's going to be another state program in Maryland, or in other states, that will promote the building of yet additional capacity outside of the market, subject to selectivity criteria that are not consistent with FERC's policy goals of cost efficiency, ones that come out of, whatever is the view of the state both in Maryland and elsewhere, and recognize that that leads to additional volatility, mostly in a downward direction of what are to be the expected future market clearing prices for capacity coming out of the PJM capacity auction.

Q. So when you described the shift in the supply curve phenomenon, which I think was the first consequence of CPV coming into the market as a result of the pricing contracts, that the shift in the supply curve causes the movement of price down the demand curve to a lower point, I think is what you were saying, isn't the same consequence likely to arise from the addition of any new generating facility in the market, whether state-supported or not?

[79] A. Yes. And that's actually a good thing for a market, because if new capacity comes into a market on its own governed by the incentives created by the market, then the tendency is for that new capacity to be efficient capacity.

And if we have more efficient capacity in the market, then there's less need for some other project, and that is reflected in the pushing down of the market price, and that gives the correct signal in terms of the timing and the level of costs that should be expended on the next and the next project.

When the most efficient project is the one that is implemented in the market, because it's being governed by incentives in PJM auction market instead

of by some more selective state program outside of the market, when it's the most efficient entrant, if it does displace the next entrant for the same reasons that I was just describing, that's the right outcome. Because then the most efficient plant is the one that will be constructed, and one that is less efficient is being pushed off, it's delayed until it's needed and the market price recovers, perhaps.

And that's the dynamic outcome of the efficient market consistent with FERC's policy goals. It's when the inefficient displaces the efficient that that dynamic of deterrence is consistent not with cost minimization, but with in fact raising the total costs of the total system needlessly.

[80] Q. Professor, we know that from the last auction results that CPV, when it bid into the auction, managed to clear the auction.

Doesn't that tell us that CPV's plant is an efficient one?

A. No.

Q. Why not?

A. The MOPR, as it applies to what the bid actually is, has a lot to do with this fact of them actually clearing the market.

The first thing to recognize is that where the market price actually cleared is not what CPV expected to get in terms of its own financing.

So what the market was paying or offering to pay other projects is the market clearing price, that's not what CPV was intending or expecting to get. It was expecting to get the magic number.

So the market clearing price governs who actually gets to construct and get the capacity revenues to help it construct in this market and who doesn't, except for CPV, or others, who are those who were being rewarded by a program like the State's program under the Contract for Differences.

So the market is not correctly selecting CPV based on CPV's own incentives about what it expects to get.

Now, the substitute for that, there is the MOPR mechanism. And perhaps that would fill out my answer to your [81] question, or perhaps I'll pause.

Q. Well, let me ask you, you've mentioned the MOPR exception, and could you describe the role of the MOPR exception plays in PJM's capacity auctions?

A. Yeah. And this connects back to your previous question, because my understanding is that what CPV actually did bid, which was a market clearing bid, was very much governed by what it was told it would be allowed to bid under the MOPR. And so that is the connection between these two questions.

So MOPR stands for Minimum Offer Price Rule, and it's a rule that comes from PJM and FERC.

And it has a lot to say about what a new resource, gas-fired resource, has to bid into the market as a floor on its bid.

And why does anybody think there needs to be a regulatory floor? It's sort of a question that has a lot of different motivations, perhaps, from different players behind it.

But the articulated purpose of the MOPR is to stop what are called anti-competitively low bids. And that's expressed by PJM and by the chief economist of the

PJM and other documents. And I think we've heard it here in this courtroom, also.

The MOPR rule is meant to cut off bids that are below some measure of the cost of the project for the purpose of [82] stopping those who would otherwise be deliberately bidding low, deliberately pushing down the market clearing price, and in an anti-competitive way. And that's a fairly narrow purpose, and I understand that's the expressed purpose of the MOPR rule.

This makes some sense economically. I think it's a valid purpose for a rule. And the valid purpose that I understand is that there could be players in the capacity market who have strong incentives to see that price pushed down.

So imagine there's a player in the market who expects to have to pay the market clearing price for its capacity. It's a big user. It's either an EDC or LSC, who's winding up paying for a lot of capacity.

And if the market clearing price were lower, then they would pay less, and that would benefit them from the business point of view.

That might motivate them to do something, which would tend to push the market clearing price down.

In economics, we call this market power from the monopsonistic, side, monopsony market power. It's one of the most awkward words in this area of economy. It's like monopoly, but it's monopsony. It's buying market power.

And so you don't want to spend as much as a buyer, so you try to push the price down is the bad incentive that's a form of market power.

[83] In this market setting, it's thought that one conceivable anti-competitive strategy for doing that is to arrange for somebody, not yourself, but somebody whom you've contracted or affiliated to bid in very low purposefully to push down the market price.

And even though you, the large buyer, might have to spend something a little extra to get that low price bid into the mark, you'll make up that cost and more by how much less you have to pay for your major buy in the market because you've managed to push the market price down.

That's a real possibility in some market circumstances. And that's why it makes some sense to have something like a MOPR in this supply side auction. So that's the purpose of the MOPR.

But it's not a price, and it's not a level that means that the offer of the capacity would be willing to go forward at that price. It's just a measure of anti-competitiveness of the bid relative to some measurement of cost.

Q. So perhaps we can walk through an illustrative example. I think we heard testimony yesterday that in the process of going to PJM to secure a MOPR exception floor for the CPV project, I think the testimony was, or that CPV proposed a floor of something like $14 and that floor was adjusted up to something like $95, I don't have the precise figure, and that floor was—that was objected to by the market monitor, but ultimately, [84] it didn't matter, and CPV bid $95 or so into the market.

Did you hear that testimony?

A. Yes, I did.

Q. And so just for illustrative purposes, CPV would be somewhere in the—on this curve on the—on the supply curve, somewhere in the vicinity of project A, I'm circling it, maybe it shows up only on your monitor.

A. Is that a hundred, Mr. Meyer?

Q. Right. I'm just locating, for illustrative purposes, a place along the curve where CPV might be. Obviously, this is not drawn with reference to the specific—

A. Right.

Q. —supply curve.

Now, so if I understand what the MOPR exception does, it establishes some form of NetCONE, which reflects cost for CPV in the view of PJM or the market monitor or some combination; is that right?

A. Well, there's the MOPR that applied to the auction in question had sort of two trenches to the way it worked.

There's a basic MOPR number, which is set by reference to some generic NetCONE, like 90 percent of NetCONE for a generic buy cycled gas-fired plant.

But as I understand it, CPV asked for an exception, I think that's the right word or exemption, which I understand means that together PJM and the market monitor would come to a [85] view of what was the MOPR level of bid that would be the minimum for CPV, not generically, but for the specific business plan, technology choice, cost figures, pertinent to CPV And that's either the $18 figure or the $96 figure give or take that you were just referring to.

Q. And the clearing price was above that, so, just again in the illustrative diagram somewhere up here,

and if it's true that CPV's costs are below the clearing price, wouldn't it make sense for CPV to go forward with the project?

A. Well, the question's what does cost really mean in this context?

If we had asked the question, the Court or counsel, of CPV, if you had been promised $18, the original suggested number for the MOPR minimum bid, would that have been enough for you to go ahead with the project?

If that question had been asked, I can't speculate about what the answer would be, but I suggest the answer might very well have been well thanks, but no thanks, that's not really what we need to get in order to go ahead with the project.

Or whether that right number is 96 or not.

The calculation of the MOPR bid floor I think it makes sense from the monopsony protection point of view, but it's not meant to be, and it is not a prediction of what would be the business consequence if that were the return from the [86] auction.

It could very well be the case that some potential supplier who would actually get the level of MOPR as their return from the auction would say, well, you know, in some sense of the accountant, that does cover some of our costs, but I think we need a year or two to see if we could do better later.

Or maybe we could move the project and come up with a different design for it and maybe get a better MOPR bid out of a different project.

Or maybe we'll just skip the new build entirely and do an uprate instead from our current locations.

Or if this were some other project, we'd just come up with a new design, because that's a pretty skimpy result for us, even though the way that PJM and the market monitor went forward in calculating the number was okay by those rules, those rules have a different function than predicting what the business would do as a result.

Q. So if we posit that CPV would not be in the supply absent the pricing contract, then would the pricing contract—how would the pricing contract's interaction with the MOPR rule play out?

(Pause)

Q. Let me try that one again.

A. Thank you.

[87] Q. So I think you've described a circumstance where the application of the MOPR rule to give CPV a floor bid does not assure that the auction results are consistent with FERC's objective if CPV would not have been in the market absent the pricing contract?

A. Exactly.

Q. And again, I think if I understood correctly, what you were suggesting is, that has to do with the fact the consequence has to do with the fact that the interaction supply and demand would be altered, the clearing price would be altered by CPV's absence?

A. Yes.

Q. Which would have consequences for investment decisions by others?

A. Absolutely right.

Q. Could you give us an example of how, even in this situation, there could be an effect on the desirable

most efficient balance or mix of resources resulting from the auction?

A. The effect of CPV not going forward, not clearing.

Q. Well, the effect of CPV coming in –

A. Yes.

Q. Coming into the market, bidding at an allowable price above the MOPR floor or at the MOPR floor and clearing the market, the effect of that on outcomes, under circumstances where CPV's [88] bid was at or below clearing price level?

A. Okay. Good. So we can make reference to this demonstrative again and see if this is responsive to your question, counsel.

So imagine that on this picture, the magic number is not the market clearing price, but the magic number that CPV is actually getting as its actual price from the pricing contract is something bigger.

Can you see, Your Honor? I'm having a hard time seeing,

But in my book, say at the level of project D, which is up at 200, so just suppose we have the measured numbers 400, but that's off this scale, so let's say the magic number for this sake of example is 200, and that's enough for CPV to actually make a decision to go forward.

So CPV is actually coming in to the market because it is assured the $200 price for capacity from the pricing contract.

Meanwhile, they actually are going to do the build, in this example, as a result of getting that return from the pricing contract, but they actually, if they'd been

getting only the market clearing price for only their MOPR bid floor, they would have said thanks, but no thanks. So now they're actually coming in.

When they actually come in, there's an effect on [89] others, because they're displacing others who might otherwise have bid, or otherwise have cleared, or otherwise gone ahead with other future oriented plans in the next auction.

But the fact that they're in and they're pushing the supply curve to the right, and they're depressing the market clearing price all amount to them, their project, displacing somebody else's project.

Now, again, it's not intentional, it's not personal, this is just the way the system is apt to work when some market player is not being exposed to the market price, but being exposed instead to a non market price through the State procurement process.

So the implication of that is that the more expensive plant, the one that's being motivated to come in by the State program, is displacing some other plant that would otherwise have cleared on the basis of what it was really getting as its price, and the result is the portfolio of resources that is not consistent with FERC's policy goals; namely, the least cost solution to the PJM reliability problems and needs.

Q. Are you familiar with or aware of various state programs, tax incentives, on the programs that express state policy goals and that may have the effect of giving incentives to generators to come into the market?

A. Yes.

Q. And is your assessment of the conflict between the pricing [90] contracts and the Maryland action in

this case, applicable as well to other sort of state programs that create those kinds of incentives?

A. Well, for example, think about state programs that are intended to be responsive to environmental concerns quite apart from the provision of reliable power at the least cost. But state programs that are concerned about the environment and therefore are intended to promote renewable resource capacity. I think that would be an example that would fit your description.

And as a result of such a state-oriented program, we hope that there will be additional renewable resources bid into the market and accomplished what wouldn't otherwise have actually been implemented without that special state program.

So it's an influence on what resources are coming into the market tending to move toward those that are based on renewable sources, and indeed having an effect on the market, because of the State program.

And at least in my view, that's a good thing. And it's not a thing that gets into the way of FERC's expressed policy goals, because it doesn't stand in the way of least cost provision of reliable power except inasmuch as these other goals of environmental protection, and we hope that those are actually accomplished through renewable power, that's a different goal than FERC's goal.

[91] I think it's a goal that, judging by federal statements generally, is one that the federal government is behind as well. It's not inconsistent with.

And to the extent there's the appearance of a conflict, it's not—it's a balancing of a different goal

along with the FERC goal of just least cost for reliable power.

Q. It's been said by the defendants in this case, or at least the State, that one of the problems with the RPM from their perspective, the capacity market within PJM, is that it doesn't express the policy goals that the State has.

It doesn't express, for example, the policy goal of wanting a gas-fired plant and wanting a new plant, wanting it now, and wanting it here in SWMAAC, couldn't you view those as a set of policy goals that the State is making, choosing, and the effect of that choice would be akin to what you just described regarding environmental interests?

A. No, not at all. Those goals that you just enumerated as being the goals of the State program that you're asking me to talk about, those goals are intrinsically in opposition to the goals that underlying the FERC policy and the PJM architecture.

The FERC goals expressed through the PJM architecture are choosing location, choosing timing, choosing all those things based on their impacts on costs in a non discriminatory way, setting up those other selection criteria not as goals, but as impedance to those goals is what creates the conflict [92] between the State program that we're talking about and the legitimate policy goals of the FERC.

That's not true when it comes to renewable resource tilting programs, because the goal for environmental protection is not at odds with any expressed goal of the FERC. It's complimentary. It's a different goal, but it doesn't run squarely head-on into it in a way that interferes with it. It augments it.

Q. So I think I'd like to transition from this discussion of your second principal conclusion to your third principal conclusion.

You've talked about the conflict between the interference to FERC's policy goals posed by the pricing contracts in the Maryland orders.

Your third principal conclusion I think you described is that the pricing contract needlessly favors the development of generation in one region within an interstate market.

Now, Professor Willig, we've heard that location matters. Why is it legitimate to favor one location or another if location matters?

A. Yes. Location does matter, I understand. It matters to the way the entire interconnected interstate wholesale system works. And it matters in a way that is fully reflected in the operations of the PJM energy and capacity markets, the auctions that we're talking about.

[93] So it matters, but it is efficiently and properly taken into account in the operations of those auctions. And so to separately introduce discrimination outside of the way that PJM's markets govern and direct incentives for the system to work, because location does matter, gets in the way of the operation of the market, and interferes with the accomplishment meant of FERC's goals.

Q. Can you explain—we haven't spent much time on this, can you explain how the auction process, the auction mechanism, establishes locational specific pricing signals?

A. Yes. So we drew the auction pictures as if there was only one supply stack and only one demand curve,

and I think that was accurate enough for the purposes of the discussions that we've had.

But the truth is that the algorithm, the way that the market clearing prices are determined is more complex, because separate supply stacks and separate reliability needs are considered by the PJM auction process incenting in setting the capacity prices within different LDAs.

And on the energy side, the way that the markets clearing prices are determined for energy are quite specific to location. And as the Court knows, these are called the LMP's, Locational Marginal Prices. And they're potentially different at different nodes of the network. Even nodes that are relatively close together can have different LMPs that applies [94] to nodes that are further apart as well.

These differentiated prices by location do the job of conveying to the market the differential values of resources and the differential costs of load at these different geographic points, and they do so in an efficient way.

Q. Are there not underlying physical constraints on the movement of energy, as you described it, in the system?

A. There are. Where there's no impact, that means anything for cost of physical constraints, we'll see no differences in the geographic prices.

So if the LMP at point A is the same at LMP price that applies to point B, it means that there's no transmission constraints basically at the time that those LMPs apply that are serving to impede the movement of power of energy between point A and point B.

If the LMPs are different at those two points, it means there's some constraint somewhere in the system that's causing that price separation, and that means that there's differential value to resources located at those two points.

The same is true about capacity prices in different LDAs, although now it's not realtime, not moment to moment the way LMPs are, but on an annual basis.

And to the extent that the value of capacity at this point in this LDA is different than the value of capacity to the system at a different point in a different LDA than the [95] capacity prices at those two LDA's will be different.

And if the LDA specific prices are the same, it means that there are no transmission constraints between those two areas that are sufficiently binding over the course of a typical year to make the prices be different.

It means that they're really not areas that are isolated from each other from the point of view of the needs for capacity.

Q. Let's focus for a moment on the LDA energy price differentials that you alluded to. Wouldn't it be a legitimate conclusion for a state, perhaps, to reach that if they're going to issue an order regarding construction of a power plant, they'd want to do so at a location where prices were higher?

A. It's interesting, because if the capacity prices are higher within a given LDA, that by itself provides a market signal that is intended to by the design of the auction system and has effect of encouraging projects to be developed for the area where the LDA specific capacity prices are relatively high.

So the market the PJM capacity market is designed and functions in such a way as to present pricing signals to encourage market reactions to bring more capacity in a variety of ways that capacity can be brought to bear to those areas where the relatively high capacity prices specific to the LDA actually will occur.

Q. Have you evaluated the conditions within the portions of [96] PJM that Maryland finds itself in, a MAAC region related to the relevance of these kinds of pricing differentials?

A. Well, one thing that we've seen here in court, and I believe it was in my report as well, that the LDA capacity price for SWMAAC has been the same as the general level of capacity price throughout MAAC.

So SWMAAC has not separated from MAAC in its capacity prices over the last four to six years, I guess it is, give or take a year.

Signifying that well, the market has not been giving differential signals to investment in new capacity projects in SWMAAC as opposed to MAAC generally, but not because the market has been neglecting the importance of geography, but because the facts of the determination of where capacity is needed and what its values are under the PJM system have had as an outcome, that there's really no difference to the system when it comes to reliability and the needs for capacity, no difference for the last some odd years between locations in SWMAAC and locations in the rest of MAAC.

Now, that's not true about RTO versus MAAC, but it is true about SWMAAC versus the rest of MAAC.

Q. Now, we've talked about a little bit about the movement of energy over transmission lines. Is there a way of thinking of those transmission lines as akin to highways that have traffic?

A. Well, let's see. Around the earth, the cars don't move and [97] the electrons don't move, so that's similar.

But, yeah, if you think about the cars as analogous to energy, there's something to that analogy. So I live in New Jersey. It's—I know it sounds strange to me, too, but I've been there for a long time. It's pretty good. And getting to New York is really a problem during rush hour, whether it's trains or cars. There's a lot of congestion on the route between suburbs of New York and downtown New York. And that has a lot of influence on how people structure their lives.

Q. And how would you describe the consequence of that congestion for the ability to call upon commuters, shall we say, in New Jersey who work in New York?

A. Yes. So you've got—if you're an employer, I guess you're a resource user, you've got to be ready to pay more to people if the place that you asked those people to come to work is downtown, then you have to pay them if they can go to work in Princeton, where life is lovely, you don't have to beat rush hour every morning.

And although people suffer by having to commute to New York, if the labor market is competitive, reasonably competitive, they're going to get paid more for the inconvenience of the workplace being in the congested area.

So that wages tend to be higher inside the congested area than they are out in the suburbs because of those real costs of choosing to have people meet those needs downtown [98] where there's congestion as opposed to where there's not congestion.

Q. And returning now to the way in which PJM auction markets and more generally energy and capacity markets function, how does PJM take account of those kinds of issues?

A. Well, there's a variety of ways. The first way is in an architecture that does make the pricing that shapes people's decisions, be sensitive to the areas and to their needs given the extent that the system is subject to congestion, which is quite natural that it be subject to congestion.

Congestion is natural, and in fact it probably would not pay to invest enough in transmission to erase all points of congestion.

And one way that PJM deals with that thought is again by the design of the system. And this is remarkable economics and not due to me, but due to others, that the difference in LMPs between two points is a reflection of the value of transmission between those two points.

And so when it comes to PJM's decision-making process about whether to build new transmission links among the inputs to that decision is what, well what are the locational differences in capacity prices and LMPs across those two points that the transmission network would connect?

So one of the things that PJM does to take into account congestion, besides having the right prices, is to have [99] a long-term transmission planning

function, which we've heard about here in this courtroom, and to promote, undertake transmission projects, in accordance with what are the felt needs of that planning process for additional transmission.

And that transmission has an impact after its built on the structure of the locational prices, because there's less congestion if a new transmission is built. And that will tend to bring pricing closer, because when prices are closer, it's because there's less constraints between their areas.

So PJM is active in allowing prices to reflect the locational impact on need and on cost. Also transmission planning. And also constructing or undertaking to have the transmission projects constructed in accordance with the felt needs of the planning process as influenced by the pricing.

Q. So to summarize, if I understood your testimony correctly, your conclusion is, as where we started, that the Maryland Public Service Commission order needlessly favors the development of generation in SWMAAC over generation in other parts of PJM?

A. Yes, exactly.

MR. MEYER: We've been going another almost 90 minutes. I believe I have no further questions, Professor Willig.

THE COURT: Okay.

MR. MEYER: Perhaps we could take a break?

[100] THE COURT: Perhaps we should take our lunch break until 1:30, is that okay?

MR. MEYER: Fine.

THE COURT: Okay. Fine. 1:30.

(Luncheon recess.)

(Conclusion of morning session)

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, et al., :

Defendant.

Baltimore, Maryland

March 8th, 2013

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendants:

H. Robert Erwin, Esquire
Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Ransom E. Davis, Esquire

[2] PROCEEDINGS

(Afternoon session 3:?? p.m.)

THE COURT: Okay.

MR. ERWIN: Your Honor, just one quick note. The parties have conferred and we have a briefing schedule we all agree with.

THE COURT: Okay.

MR. KLEINMAN: I think it comports with what you wanted to do. We expect to file initial briefs on Tuesday the 26th, reply briefs on Friday April 4, and then, of course, we've scheduled argument for the 16th.

THE COURT: That's fine. Anastasia, would you make a note of that.

MR. KLEINMAN: April 5th. Okay. Friday April 5th.

CROSS-EXAMINATION

BY MR. KLEINMAN:

Q Good afternoon, Dr. Willig.

A Good afternoon, Mr. Kleinman. Or is it Dr. Kleinman.

Q Litigation leads to funny relationships, doesn't it? In any event, I'd like to talk to you about the opinions in the order in which you displayed them on PD-72. First, your opinion that "The PSC order and the CfD set a price for wholesale sales of energy and capacity, displacing the price that PJM auctions are designed to set." Can you tell me what you mean by the word "displacing"?

* * * *

[45] correct?

A Correct.

Q You would conclude, would you not, that having done so,the CPV's plant is a resource that has demonstrated that it is needed by the market, and it is, therefore, economic as FERC—not an economics textbook—but as FERC states what is need by the market and economic entry, correct?

A Well, in these words of the FERC, they do apply to the situation that you're talking about.

Q You would also agree would you not—

A Let me finish, those are the words of the FERC. But I don't think that they're right from the point of view of real economics. And I'm not sure that FERC takes those words to mean what they mean to me as an economist looking at them.

Q Well, I appreciate that.

A Okay.

Q But we are all reading these words, you may be the only economics Ph.D. in the room, and lord knows you're a very good one.

A Thank you.

Q But we are all looking at the same words. And that suggests that in FERC's view, does it not, that CPV, having played by the rules, satisfied PJM, made its bid no lower than it was permitted, and clearing the BRA, has demonstrated, at least to FERC, that in FERC-ese, CPV is needed by the market [46] and is, therefore, economic?

A In FERC-ese that is exactly what it says.

Q And you would also agree, would you not, that having bid in conformance with the rules, cleared the BRA, CPV is a resource that in the market, at this point, does not artificially suppress market prices?

A Those are the words of this paragraph here by the FERC, despite the fact that logic does not actually support the real economic meaning of that idea. So I can only assume that this has narrow meaning within the language that FERC uses legally to explain itself, because it's just not logical as a matter of economics or policy.

Q Well, they're FERC, be that as it may. Let me ask you to turn to the next page, page 54, paragraph 177 What we saw here was the Independent Market Monitor suggest that FERC add a requirement that the resource show it is not receiving discriminatory subsidies, right?

A Yes.

Q And FERC declined to add this requirement, correct?

A That's what it says.

Q Because it concluded, "If the resource is needed at the MOPR bid, then it is a competitive resource, and should be permitted to participate in the auction regardless of whether it also receives a subsidy," correct?

A You've read it correctly.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND/NORTHERN DIVISION

CIVIL NO. MJG 12-1286

PPL ENERGYPLUS, LLC, ET AL.

Plaintiffs

v.

DOUGLAS NAZARIAN, ET AL.

Defendants

March 11, 2013

DAY SIX BENCH TRIAL MORNING SESSION
BEFORE THE HONORABLE MARVIN J. GARBIS,
UNITED STATES DISTRICT SENIOR JUDGE

APPEARANCES:

On behalf of the Plaintiffs:

David Meyer, Esquire
Stuart Plunkett, Esquire
Richard Roberts, Esquire

On behalf of MPSC:

Robert Erwin, Esquire
Ransome Davis, Esquire

On behalf of CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[4] Pacific. We have George Loehr, an electrical engineer about reliability, and we have Matt Kahal, the State's closing economist.

THE COURT: All right. Well, let's do our best for all concerned, please, go ahead.

MR. ERWIN: Your Honor, the defendants call Dr. Craig Roach.

THE CLERK: If you'll raise your right hand.

(Oath administered.)

THE CLERK: Please be seated. If you would, sir, state your name and then spell your name for the record.

THE WITNESS: It's Craig R. Roach, C R A I G, R O A C H.

DIRECT EXAMINATION

BY MR. ERWIN:

Q. Good morning, Dr. Roach good morning.

A. Good morning.

Q. Are you employed?

A. I am.

Q. Where are you employed?

A. I'm the president of Boston Pacific Company, Incorporated.

Q. And how long have you been with Boston Pacific?

A. Since I founded it 26 years ago.

Q. And what are your duties as president?

* * * *

[65] A. That's what it says, yes.

Q. And you actually reviewed this document, and you took some notes on it; do you remember that?

A. I believe I did review this. I would of course take notes, because I do that.

Q. Let's take a look at plaintiffs' exhibit 212. Is this the report you reviewed?

A. Yes. I actually even see some handwritten comments from me in here.

Q. I do, too. Let's look at one of them. If you could turn to page ES 1.

Last paragraph, it says in addition to the alternative scenarios noted above, table ES 1 also identifies four scenarios developed in response to comments received on earlier drafts of the LTER. These supplemental responsive scenarios address the construction of a natural gas plant in advance of reliability requirements.

This was a passage that you read, correct?

A. Correct.

Q. And those are your notes over to the right; is that right?

A. Correct.

Q. Can you tell me what those notes say?

A. The whole thing says four other scenarios, these are partial words, I'll read them, four other scenarios, one, natural gas in advance of reliability need.

[66] Q. All right. You can put that document away.

By the way, just to be clear, there was nothing in this report that caused you to alter your opinion that it would be reasonable for the Commission to not issue the RFP, but instead to continue studying the matter, right?

A. I continued to believe that it's the Commissioner's call. The commissioners are the ones who should on behalf of the ratepayers judge the extent of the risk, and they're in the best position to judge the risk tolerance of their ratepayer. So it's their decision.

Q. In your testimony to the Commission on January 31st, 2012, you discussed Boston Pacific's understanding of the purpose of the RFP; did you not?

A. Yes.

Q. Let's take a look at what was said. Going back to exhibit D 115 of your report, let's go to the page 1, page 034, depending on what you're looking at.

In this section, the second section here below the introduction, it says what the RFP is and is not about.

And you say it most certainly is not about under mining the PJM capacity market, the Reliability Pricing Model, or RPM.

That was your testimony, right?

A. Correct.

Q. And I think you repeat the point in the next sentence. You [67] say "Put bluntly, it is not about

subsidizing new unneeded generating capacity with the goal of artificially reducing the RPM price."

Did I read your testimony correct there?

A. Correct.

Q. In fact, Mr. Roach, the purpose as you understood it from the beginning of your engagement, at least one of the purposes of the RFP was to lower energy prices including lowering the capacity price; isn't that true?

A. No. I think what is said here is what I believed on that day and I continue to believe. The RFP can affect prices and it can lead to lower prices.

I have no problem with the Commission being interested in that, but again I don't—I don't think the intent is to undermine in any way the PJM capacity market.

We go on in this paragraph to mention FERC's minimum offer price rule, which would prevent inappropriate bidding on economic entry. So I continue to believe and now we know that CPV Maryland did clear the MOPR process. So I think this is an accurate statement.

I don't think we ever thought it was just about lowering the price. Although it could easily lower the price.

Q. Let's take a look at plaintiffs' exhibit 143.

Do you have it in front of you?

A. I do.

[68] Q. This is an e-mail chain, so let's start at the bottom. There's an e-mail from you to Calvin Timmerman and Gregory Carmean.

Do you see that?

A. Yes.

Q. This is dated January 28, 2011, that's very shortly after you were engaged by the PSC staff to assist them in commenting on the RFP, right?

A. That's right. And that's important. This, here we're working for the staff of the Commission, not the Commission. But yeah this is Calvin Timmerman and Gregory are high in the hierarchy of the staff.

Q. And you were engaged by them to evaluate the RFP and help them comment on it; is that right?

A. That's correct.

Q. Okay. So let's move up to the next e-mail in the chain. This is from Mr. Timmerman with the PSC to you on the same day, January 11.

Do you see that e-mail?

A. Yes.

Q. All right. Let's start with the sentence to buy, which is three lines down.

This e-mail says "To buy any resource that exceeds that estimated cost, you need to have some specific reason, such as concern that the RTO reliability process will fail to [69] provide adequate resources or some other policy on the objective like GHG reductions. Reliability concerns led to our Gap RFP for DR resources. In this case, the Commission expresses concerns that RPM isn't producing adequate new capacity, but unlike the Gap RFP, PJM's numbers don't suggest any capacity crisis."

Did I read that correctly?

A. Yeah, that's what Mr. Timmerman wrote.

Q. Okay. And then it continues, "It really seems to be the hope that this RFP will produce cheaper capacity and energy than you get from the market. I know this was some of what you wanted to say originally, and I'm coming around to adding that."

Did I read that correctly? Is that what Mr. Timmerman told you in this e-mail on January 28?

A. That's what it says, yes.

Q. Okay. And you responded to this e-mail; did you not?

A. I would imagine I did.

Q. Okay. Let's scroll up. You responded about an hour later; didn't you?

A. Okay. This is the one that says great. Thanks. And then I proceed to speak of weather in the deep south.

Q. My question is, when you responded an hour later, did you correct anything that Mr. Timmerman had said about your views on the RFP? You didn't, did you?

[70] A. No. Well, there's nothing to correct. The point is, if I read this, and again these are e-mails from a fair distance in the past, but if it says, you know, that we will hope to produce cheaper capacity and energy than you get from the market, I think that's a good goal.

What that says to me is that we're hoping that if we were to run this RFP, we would get a lower cost resource.

And you know, I think we did. I think if you look at the product either as a long-term capacity product, in that case, you look at, we ran the RFP, and we took the

cheapest bid. So I think we got something that was below the alternative.

So we achieved that goal. Even if you perhaps wrongly define this as short-term capacity, we've been talking about the MOPR screen, CPV Maryland, the winner of the RFP, cleared that MOPR screen, and in fact was lower than the actual market price.

So I read this as saying not let's lower the price, but that I hope we get a resource. I hope we get a competitive resource that is the lowest price possible. I think that has been done here.

Q. Let's take a look at what you said a few months later in your key points outline, exhibit P 203.

That should be in front of you.

A. I have it.

[71] Q. If you go to page 3 of this outline, at the top, it says "While there appears to be no immediate reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks and possibly bring economic benefits. "

Do you see that?

A. Yes.

Q. Okay. And then if you turn a few pages over, to page 6,

A. I apologize, I can follow it on the screen. My copy, unless I picked up the wrong thing, doesn't have all the pages you're referring to. But can we follow it on the screen?

Q. Yes, we can. I apologize for that.

So if you look on the screen, we're going to highlight subpart C.

It says "The economic benefits of new generation are potentially great, but very uncertain."

And then you list the potential economic benefits. The first one you list is that new generation in SWMAAC could serve to lower the RPM price. And in the second one, you list is that new more efficient capacity could lower local LMPs.

Did I read that correctly?

A. Yes.

Q. That appears in your key points outline?

A. Sure.

Q. So from this outline, you prepared your report, which is at P 042, right? If you pull up your P 042, that's the report you [72] prepared a month later?

A. Sure.

Q. Okay. So on P 042, we take a look at the third page of the document, which is the table of contents, IV, we see the same heading, "While there appears to be no imminent reliability threat to Maryland, the issuance of an RFP could serve to mitigate several risks."

But there's no subpart D. Am I correct that from the report you issued to the Maryland Public Service Commission, you deleted the references to lowering capacity and energy prices as being one of the purposes or benefits of the RFP?

A. Yeah. I don't think so. You're traveling down the road where again you seem to be implying that the purpose was to inappropriately reduce prices. And I don't think that's what's reflected here at all.

Again, the CPV Maryland project was the lowest cost bid, so for long-term capacity, there's evidence that it beat the market, so to speak.

And even for short term capacity, it was cleared in the MOPR, and so there's nothing—there's nothing inappropriate about its bid. It's been tested for uneconomic capacity for FERC and PJM about to bid.

Now, the result, because it's an increase in supply, the market price will – or the clearing price will fall. But I don't agree at all with this implication that there was some [73] purpose to inappropriately, that is, untested for uneconomic capacity to lower the price, I don't see that.

Q. Sir, I'm not asking you about the implications. My only question is whether I'm correct that the section on economic benefits, including lowering the capacity and energy prices was deleted in the report, deleted from the outline when you prepared the report, that's my only question.

A. If all you're saying is you don't see item C on page 6 in the full document, then I'll take your word for it, that you don't see it.

Q. All right. So you've offered various opinions in your report in this case, and you offered some in your testimony regarding state regulation of energy markets.

And I want to clarify that you're not a lawyer; is that correct?

A. Correct.

Q. Okay. And you don't consider yourself an expert on the boundaries between state and federal authority, correct?

A. Certainly not as a legal expert. As an observer, seeing what's actually going on, I can help with some facts. But I'm not giving legal opinions.

Q. Okay. So you offered various comments about Standard Offer Service procurement. In your view, Standard Offer Service procurement is a significant departure from the procurement used in the RFP in this case, right?

* * * *

[106] define where a generator plant – where a generation facility would need to be built; isn't that right?

A. No. I mean take the Judge's numbers, these are purely hypothetical, but in the example, the clearing price out in Pennsylvania is 120 per MW day. The clearing price in SWMAAC is 150. That means that a transmission constraint has made the people of Maryland pay a higher—pay a premium. 30 more dollars.

That premium isn't eliminated because there are other Pennsylvania plants, that capacity may be there, but it can't be delivered to SWMAAC.

So if that were true, there wouldn't be this price difference. If that excess capacity in Pennsylvania could be reliably delivered to SWMAAC, we wouldn't have price.

Q. I'm not sure that's an accurate description, but I think we should move on.

Let's go back to what you were telling the Maryland PSC about the locational restriction that they ended up adopting. And I think the place to start is your August report, which is P 042. So I'd ask you to pull that up.

And if you could refer to page 37 of that document, the conclusion?

The last paragraph of the conclusion, are you on that page?

A. I am.

[107] Q. Okay. Last paragraph, you said the "RFP should be targeted specifically to mitigate the risks laid out above. To that end, our main suggestion was to limit the RFP to only new natural gas-fired combined cycle generation located in SWMAAC or EMAAC."

Is that what you told the Maryland PSC in August 2011.

A. Yes, with clarification as we've discussed before and as noted that we're talking about the Maryland portion of EMAAC, but yes.

Q. Just the Maryland portion?

A. Yes.

Q. Okay. Let's take a look at page 4 of this.

You state right below paragraph, or the subsection 5, to effectively mitigate the risks above, we believe the RFP should specifically solicit only new in state natural gas-fired combined cycle generation located in SWMAAC or EMAAC.

So what you're telling the Commission is that it needs to be located in Maryland, but it can be located in either one of those places?

A. That's what we said in the August report, yes.

Q. And was that your advice consistently throughout your engagement with the PSC?

A. I think it evolved over time, but we clearly made that suggestion to the Commission in this report.

[108] Q. I think it evolved, also, and I'd like to walk you through that a bit. And you can tell me if I've gotten it right.

First of all, you said you were engaged by the staff in January 2011, right?

A. Thereabouts, yeah.

Q. Okay. And before you were engaged, there had already been a couple of orders from the PSC that addressed the locational requirement, true?

A. Yes, if you mean there had been – I recall a draft RFP in 2010 that had a locational requirement.

Q. Let's take a look at the documents. Let me refer you to P 035.

Do you have that in front of you?

A. Yes.

Q. It's a September 29, 2009 order from the Public Service Commission, and if you turn to page 3 of this document, at the top, it says the Commission hereby directs all parties interested in making proposals for new Maryland-located electric generating facilities.

Do you understand this to mean that had this locational requirement remained place that generators would have been able to build anywhere in the State of Maryland?

A. I don't have a problem interpreting it that way. I don't recall this document, but that's what it says.

Q. Okay. So let's put up PD 95.

[109] This is intended to be a representation of the locational requirement in the PSC's September 29, 2009 order. Look correct to you?

A. I understand it's showing the location would be in Maryland.

Q. Okay. Let's take a look at P 013.

Do you have that in front of you?

A. Yes.

Q. Okay. If you go to page 3 of this document, this is a PSC order dated December 29, 2010, a couple months after the order we just looked at.

On page 3 of this document, the locational requirement is defined a bit differently. "Products must be derived from generation capacity resources that will be located in or around Maryland so long as such generation capacity resources interconnected to the system such that the generation capacity resources output is infed to a node east of the western interface and deliverable to Maryland east of the western interface."

Did I read that accurately?

A. Yes.

Q. Okay. If you could pull up plaintiffs' demonstrative 90.

Again, we've attempted to depict the locational requirement as we understand it. Does that look right to you?

A. Yeah. I think this is a fair characterization with one [110] caveat, and that is the use of the word deliverable. I don't think we ever understood—we

didn't write this document. We weren't in the engagement yet.

So if—with that without the word deliverable would that have acted to constrain the location of the plant to a much narrow area. That's my one caveat.

I see what you're doing, I don't have a problem trying to draw the geographic.

Q. With that caveat, you generally agree that the locational requirement had changed and a generator could now be built in multiple other states?

A. Yeah. With—put the caveat aside, that's what that language would suggest.

Q. Okay. Let's take a look at P 042.

This is your August report. And this—have you pulled that up? P 042?

A. Page 37?

Q. Yeah. Page 37.

A. Okay.

Q. On page 37, you say SWMAAC and EMAAC but you clarified that that would only be in Maryland. So I don't have a map for this, but you would agree that as of August in your report, the proposed locational requirement had changed and no longer included multiple states, it only included a part of Maryland, fair statement?

[111] A. That's correct.

Q. Okay. Now, you had discussions with the PSC about this locational requirement after providing that report; did you not?

A. I would think that we did, yes.

Q. And the location continued to change during those discussions; did it not?

A. Well, as evidenced by the fact that it went out in SWMAAC.

Q. Good point. But it changed more times than just that. Let's take a look at P 028.

Now, this is an e-mail from you to Mr. Bender at the Public Service Commission; is that right?

A. Well, it's an e-mail from Frank Mossburg, my colleague, to him.

Q. I'm sorry. It's an e-mail from Mr. Mossburg. But you've seen this e-mail before, correct?

A. I would think so.

Q. Okay. And I just want to point out –

A. Although I'm not cc'd on it.

Q. I just want to point out the language on the first point here, where it says we tried to make changes exclusively related to our recommendations in the report. So the key change is that the RFP looks only for new cc capacity in Maryland, in SWMAAC, or EMAAC.

A. Correct.

[112] Q. So this is a communication to the Commission that your report reflected a change from the Commission then existing locational requirement, right?

A. Correct. From the broad east of the western interface kind of language, yeah, that's right.

Q. Okay. Now, let's jump forward a few days and take a look at P 230.

Do you have that in front of you?

A. Yes.

Q. Okay. September 21, 2011, shortly after the communication we just saw, Mr. Bender sends an e-mail to Mr. Mossburg, with revisions to the RFP Do I have that right?

A. Yes.

Q. Okay. So go to page 3 of the PSC's revisions.

A. I've got it.

Q. Under 2.1, product definition, it says the products must be delivered from generation capacity resources that will be located inside the SWMAAC or EMAAC locational deliverability areas.

Did I get that right?

A. That's correct.

Q. Can you pull up plaintiffs' demonstrative 96? Does this map accurately demonstrate the locational requirement the Public Service Commission proposed on this date?

A. I don't think so. I think it is the same as ours, whereas [113] the only location in EMAAC that would be eligible would be the small part that consists of Maryland. That's what I believed.

Q. Let me ask you again to take a look at the language on page 3.

And if you compare that to the language we saw in the prior exhibit, they took out the words "in Maryland;" did they not?

A. Yeah.

Q. Okay. So if you take out the words in Maryland, and you're talking about SWMAAC and EMAAC, then you're talking about the pink area on PD 96, the map that's on your screen; is that true?

A. If that's what they intended, then, yep, we would include the opinion, the pink colored Southwest and eastern.

Q. You would agree with me that the pink area on this map includes multiple states?

A. Yeah, includes New Jersey, Delaware, yes.

Q. Any other states?

A. Some of Pennsylvania.

Q. Okay. And it also includes some of Virginia, doesn't it?

A. Yeah, I think so. It's part of Delmarva.

Q. So a total of five states where the PSC was proposing the generation could be built, if you're reading this document correctly, right?

A. Well, if I'm reading it correctly, no, but you're reading [114]—I understand the confusion. It says SWMAAC, EMAAC you can take that literally. I think, you know, I said what I said. But I thought it was just the Maryland portion, but that's okay.

Q. So there was a phone call, a day later, between Boston Pacific and the PSC, right to discuss the locational issue? A. I don't recall. I don't know if I was on that call. It could have been Mr. Mossburg.

Q. Okay. Well, let's take a look at P 209.

This is a September 22nd 2011 e-mail day after the document we just reviewed. And this e-mail is from your colleague Mr. Mossburg to, Mr. Bender at the

PSC, you're copied on it. This is an e-mail that you received, right?

A. Yeah. Finally.

Q. Exactly. If you look at the first paragraph of the e-mail, it says "Attached please find the RFP in both red line and clean versions with the edits discussed in our phone call. Generally speaking, there were very few major changes apart from the location requirement."

Do you see that?

A. Yes.

Q. Did I read that accurately?

A. You did.

Q. Now, if we look at page 4, the location requirement has changed, hasn't it, under 2.1?

[115] A. Yes.

Q. What had it changed to?

A. SWMAAC.

Q. And is that accurately displayed in PD 93?

A. Yes.

Q. So this change had the effect of eliminating four other states where generation could have been built to satisfy the RFP; is that true?

A. Again, I don't think so. I think the meaning of the previous document, even though it is not clear, I think the previous document was SWMAAC plus the Maryland portion of the EMAAC. But I can't show you right now. I understand your interpretation is fair. My understanding is, it didn't eliminate four states

because we were only considering the Maryland portion of Delmarva peninsula, but it's unclear.

Q. When you testified before the Commission on January 31, 2012, was it your testimony that new capacity bid into the RFP must be built in SWMAAC? This is the right location by definition.

A. I'm sure—I wouldn't be surprised if that's in there. I'm not finding the document real quick, but if you're reading it, sure, I think that makes sense.

Q. So the PSC did in fact end up restricting the RFP to SWMAAC, correct?

A. Correct.

[116] Q. Okay. And they did that in the April 12, 2012 order?

A. That sounds right.

Q. And so now we're back where the PSC started, in the order back in 2009, the generation has to be located in Maryland, and specifically in SWMAAC, right?

A. That—

Q. Right?

A. That sounds fair.

Q. If you could take a look at P 044.

THE COURT: When you say Maryland, you're including D.C.?

Q. Yes, sir.

THE COURT: Okay.

Q. Have you seen this order before?

A. I believe I have.

Q. I took a look at this order to determine the basis that the PSC used for the locational requirement, and I believe it's in a footnote on page 24.

A. I'm on page 24.

Q. Okay. Footnote 139.

A. Okay.

Q. The sentence that starts three lines up, "In addition, because of the transmission constraints in SWMAAC, the new generation must be located there to address the need and there is no other means to address our purpose."

[117] The analysis here about transmission constraints, that was your analysis, correct, of the locational requirement that was necessary for the RFP?

A. I'm sorry, I'm not understanding.

Q. My question is, the transmission constraints that are discussed here are the ones that you advised the PSC justified the locational restriction to SWMAAC?

A. I don't think that's unfair. I can't know exactly why they wrote what they wrote, but I wouldn't think that's unfair to say.

MR. PLUNKETT: Okay. Fair enough. Thank you.

MR. ERWIN: Just a couple quick questions, Your Honor.

THE COURT: Yes.

REDIRECT EXAMINATION

BY MR. ERWIN:

Q. Dr. Roach, do you recall on cross-examination counsel asked you about the cancellation of PATH and MAAP?

A. Yes.

Q. And that was done because PJM no longer projected they would need them in their new forecasts, right?

A. Correct.

Q. What would have happened in 2015 and 2016 and 2017 if their new forecast was wrong and it turned out that PATH and MAAP were needed in that timeframe?

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF
MARYLAND NORTHERN DIVISION

CIVIL NO. MJG-12-1286

PPL ENERGYPLUS, LLC,

Plaintiff,

vs.

DOUGLAS R.M. NAZARIAN, et al.,

Defendant.

Baltimore, Maryland

March 11th, 2013

The above-entitled case came on for a bench trial before the Honorable Marvin J. Garbis, United States District Judge.

APPEARANCES

For the Plaintiffs:

David L. Meyer, Esquire
Stuart C. Plunkett, Esquire
Richard L. Roberts, Esquire
Mark D. McPherson, Esquire

For the Defendant MPSC:

H. Robert Erwin, Esquire
Ransom E. Davis, Esquire
Kristen Lawrence, Esquire

For Defendant CVP:

Joel B. Kleinman, Esquire
Larry F. Eisenstat, Esquire
Daniel A. Broderick, Esquire

* * * *

[2] PROCEEDINGS

(Afternoon session 1:53 p.m.)

MR. BRODERICK: Good afternoon, Your Honor. My name's Dan Broderick for the defense. Defense would like to call George Loehr.

THE COURT: Okay.

THE CLERK: Raise your right hand.

GEORGE LOEHR, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE CLERK: Please be seated. If you would, sir, adjust that microphone to yourself.

THE WITNESS: Okay.

THE CLERK: That's good. That's actually a little too close. State your name and spell your name for the record.

THE WITNESS: George Loehr, L-o-e-h-r.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. BRODERICK:

Q Mr. Loehr, by whom are you currently employed?

A I'm self-employed.

Q Do you provide consulting services?

A I do a variety of things, consulting, expert witness, teach courses, so on. And I serve on the boards of a couple of

* * * *

[60] maybe five minutes or not.

THE COURT: Yes, this would be a good time.

(A recess was taken.)

THE COURT: Yes, Mr. Meyer?

MR. MEYER: Before we all race to the doors at the end of the next examination, I thought I'd just put two brief housekeeping matters on to the record. The first, yesterday when Mr. Kleinman was recounting, or maybe it was this morning, recounting the agreed briefing schedule for post trial briefs, I believe he may have misspoken as to the date for reply briefs. We think he said Friday April 4th, what he meant was Friday April 5th. April 5th is the date.

Then second, you may recall the proffer that was filed by the state on the first day of trial. To the extent there's any response to that, we'll be addressing that in our post trial briefs.

THE COURT: Okay. Thank you. All right, Mr. Davis.

MR. DAVIS: Thank you, Your Honor. Ted Davis for the Maryland Public Service Commission. We call Matthew Kahal.

THE CLERK: Stand and raise your right hand.

MATTHEW I. KAHAL, called as a witness, being first duly sworn, was examined and testified as follows:

THE WITNESS: Yes, I do.

THE CLERK: Please be seated. And if you would [61] adjust that microphone to yourself. It bends at the top if that helps you out. State your name and spell your name for the record.

THE WITNESS: Matthew I. Kahal, K-a-h-a-l.

THE CLERK: Thank you. Counsel.

DIRECT EXAMINATION

BY MR. DAVIS:

Q Good afternoon, Mr. Kahal.

A Good afternoon.

Q Unless there are any unforseen developments, you have the honor of being the last witness in this interesting case. Please start by describing your educational background.

A I hold BA and MA degrees in economics from the University of Maryland, have completed all coursework and examination requirement from the Ph.D. from that same school, at University of Maryland at College Park.

Q Very good. And where are you currently employed?

A I'm employed as a independent consultant. I work out of Charlottesville, Virginia. And I also operate out of an office in Columbia, Maryland.

Q Can you describe the types of proceedings or subject matters that you're involved in?

A Yes. I've—I've been involved in economic and regulatory and energy consulting for the past 35 years. Approximately the last 12 years as an independent consultant.

* * * *

[118] into voluntary bilateral transactions.

Q Okay. Now, you've read the RFP it sounds like, that—

A I'm familiar with the RFP

Q The pricing contract?

A Yes.

Q Do you know—have you—you said you read the order as well that resulted from it, correct?

A Well, I think there are two orders. There's the April 12th, 2012 order, and then I can't remember the date of the other order. But then there's the date associated with the issuance of the—of the RFP itself.

Q Okay.

A It was sometime in 2011. I don't remember the date.

Q Okay. And in that order it's correct, is it not, that the Public Service Commission required the EDCs to enter into the pricing contracts for differences?

A That's correct.

Q Okay. One point that I want you to—I think I heard you say this a couple of times earlier this afternoon, but I just want to make sure that I heard you correctly. At your deposition, and I want to quote from it just so that I don't mischaracterize what you said.

A Sure.

Q "I think of the price in the CPV contract as being a type of wholesale market price"?

[119] A That's right.

Q That's still your view?

A Yes, that's my view. It's a market price because it was determined by a competitive RFP.

Q Right. But that process, that RFP process was run by Maryland, correct?

A That's correct.

Q Not by FERC or PJM?

A Yes, that's correct. It was done at the direction of the Maryland Commission.

Q Right. And the Maryland process, as you described, extensively imposed different limitations than would a PJM auction, correct, such as the location, the timing of the power plant, things like that?

A No. I don't mean to be—resist your question, but the problem is that PJM does not get involved in long-term transactions. So there's no comparable PJM process that you can use as an analogy to what the Maryland Commission did. PJM markets are only spot markets. This is a long-term contract.

Q Fair enough. Thank you. Now, I don't want you to tell me the number if you know it, but can you tell us if you know the price that is set in the Contract for Differences?

A I don't know. You know, I think I saw it on one—

Q Again, I don't want you–

A But I don't remember it. I don't remember what it was.

[120] Q Okay. Now, even if you don't know what the actual number was, I believe you told me in your deposition that you reviewed Boston Pacific's forecasts of the revenue streams under the pricing contract, correct?

A Yes.

Q And those forecasts show that CPV would receive less from the PJM market than it would under the pricing contract for the first five years, and that it would receive more from the market in later years, correct?

A Yes, I think there was a cross over after a couple of years.

Q Okay. Now, I want to clarify your views on one point that you came back to a few times in your testimony. Your—you described plaintiff's argument as—because the pricing contract effects price, it must be pre-empted by federal law, is that your understanding of what plaintiff's arguments is?

If it helps, take a look at page 28 of your report. And in the middle of the middle paragraph, in the sentence that begins "Thus, it cannot be legitimately argued that a capacity supply action is either improper or

contrary to FERC policy, merely because it has the effect of increasing or decreasing a PJM auction price."

A Yes. And now, I'm sorry, what is your question?

Q My question is—maybe instead I'll ask it in a open ended way, what is your understanding of what plaintiff's [121] argument is concerning pre-emption in this case?

A My understanding, and this is from the lawsuit that was filed around the beginning of 2012. I know there have been some expert reports since then, but I was just focusing on the lawsuit that was filed. There's – there's language in the lawsuit. And I think I cite to it earlier in my expert report, that basically accuses the Maryland Commission of trying to regulate wholesale markets and to set wholesale prices. And that sort – there's a lot more language in it – but you know, interfere with FERC's jurisdiction over wholesale markets. That sort of thing.

Q Right. And what is the sort of thing that you think plaintiffs point to as the interference with the FERC market?

A They were essentially saying that the Commission's order of April 12th, 2012 did those things, interfered—had the effect of interfering with wholesale markets, and of setting wholesale prices. That's what I understood the lawsuit to be arguing. And I'm simply saying that's not correct. It's simply—I don't mean in a legal sense, I simply mean in a factual sense. That's simply not what the Commission's doing.

Q And that's because?

A Well, that's because that the Commission is simply conducting an RFP, which as I indicated, is

simply standard industry practice. When you conduct an RFP, it's the market [122] that sets the price. It's not the Commission that sets the price.

Q Okay. Understand—

A The Commission had no say over what CPV's bid was.

Q Understood. I understand your position. I just wanted to make sure that we understood your position. You've made that clear. And we explored that market issue earlier.

A Yeah. Sorry to go on.

Q That's fine. Near the end of your testimony, you refer to certain market barriers. And to summarize what I think- you were trying to say, and I think you said it a little bit more directly in the deposition, what you're saying is obtaining financing could operate as a market barrier, correct?

A Yes, it could operate as a barrier to entry, what economists call barriers to entry.

Q Okay. Now, the—and your point, though, is that the lack of a long-term contract makes the investment decision risky, correct?

A Risky or potentially unfinanceable. Risky not only to the equity investors after CPV, but also risky to those who would lend CPV the money to finance the project.

Q Right. But then isn't that risk to those potential financers just a form of cost?

A Absolutely and costs can be barriers to entry. It's an inordinately high cost. And it's a cost that can be so high

* * * *

[151] Q Okay. Just as a final point, let's look a little bit more closely at that scenario that you agree CPV did request.

A The—yeah, I read Appendix L as they did request the early natural gas plant scenario.

Q Okay. So let's look at that, that's at L-1 it begins.

A Yes.

Q And I want to look at the table on L-3. So this is slightly confusing to me, but the line with the Xs in it, is the MSD scenario, correct?

A Yes.

Q And that's the scenario included in the LTER reference case, correct?

A Yes.

Q And then the line without any X through it is the scenario that CPV requested, NGP plus MSD, correct? In other words, new gas plant?

A That's what I understand, yes.

Q And is its a fair reading of this to show that without the new gas plant coming in in 2015, a new gas plant would have come in in 2020, that's the X?

A I think that's the assumption, yes.

Q Okay. And with the new gas plant, the new plant doesn't come into existence until a year later in 2021, correct?

A Yes.

Q So the model that PPRP ran showed that if you add a new [152] plant to come online in 2015, it pushes

out a potential new entrant by one year that would have come in later, correct?

A Yes.

Q Okay.

A Yes. That's what's being assumed here, yes.

Q And this is a model of when the first economy entry would occur, correct?

A You're talking about this scenario?

Q Yes.

A Yes.

MR. MCPHERSON: Thank you, Mr. Kahal. Nothing else.

THE COURT: Okay. Anything else?

MR. DAVIS: Your Honor, maybe just one or two potential questions. One preliminary matter, though, before we begin. The LTER was Defense 224. And I think Mr. Meyer, you mentioned that Attachment H was not part of that. I just wanted to make certain that we have in the record a exhibit which reflects fully, the entire LTER and all exhibits, including Attachment L we discussed in direct, and Attachment H we discussed in cross, the entire LTER, would you object to that?

MR. MEYER: I have no objection to having the complete LTER.

THE COURT: Why don't you take that up with Mr. Thompson, and you'll make sure it's all there.

* * * *

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MARYLAND

Civil Action No. 12-1286

PPL ENERGYPLUS LLC, et al.,

Plaintiffs,

vs.

DOUGLAS R.M. NAZARIAN, in his official capacity as Chairman of the Maryland Public Service Commission, et al.,

Defendants.

DEPOSITION OF BOSTON PACIFIC COMPANY, INC.
By and Through Its Designee
FRANK MOSSBURG
Washington, D.C.
Wednesday, January 30, 2013

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[2] January 30, 2013
11:47 a.m.

Deposition of FRANK MOSSBURG, as the designee of Boston Pacific Company, Inc., held at the offices of Dickstein Shapiro, 1825 Eye Street NW, Washington, D.C., pursuant to Notice, before John L. Harmonson, a Registered Professional Reporter and Notary Public of the District of Columbia.

* * * *

[4] PROCEEDINGS

FRANK MOSSBURG, after having been first duly sworn, was examined and did testify under oath as follows:

EXAMINATION

BY MR. MEYER:

Q. Would you state your name for the record, please.

A. Frank Mossburg.

Q. And where are you employed?

A. Boston Pacific Company.

Q. And what do you do there?

A. I'm a managing director.

Q. What does that mean?

A. It means I'm in charge of a lot of our business, basically on the day-to-day level, particularly things like the monitoring and evaluation of procurements for states, particularly wholesale full requirements, procurements as well as unit-contingent procurements.

Q. Can you explain to me as you understand it the difference between a

* * * *

[94]call?

A. I can't recall.

(Exhibit 35 marked for identification and attached hereto.)

Q. So I've marked as Exhibit 35 a two-page set of notes. It appears to be from the same spiral notebook as the set of notes that were marked as Exhibit 34.

Mr. Mossburg, are these notes at Exhibit 35 also your notes?

A. Yes, they are.

Q. Have I concluded correctly that you kept a spiral notebook relating to your work on this project?

A. I have a spiral notebook with notes from many of my projects, and 'I: produced photocopies of the relevant pages for your document request.

Q. I see.

So this set of notes reflected as Exhibit 35 was prepared later, presumably farther into the notebook, and prepared on August 2nd. Am I reading correctly?

A. That is the date I wrote at the top.

[95] Q. Okay. And there is a list of names at the top. Can you read those?

A. Sure. Frank Bender, DN, that would be Chairman Nazarian. Bob Erwin. I believe the other one is Brian Moorhouse.

Q. Brian Moorhouse at the Commission?

A. Yes, I believe so.

Q. This was a phone call?

A. Yes.

Q. You were the only one on the phone call from Boston Pacific?

A. I don't recall.

Q. So the same question.

A. Okay.

Q. You're better at reading your handwriting, than I am. It looks to me that the first line is key points outline.

A. Yes.

Q. So am I right in understanding both from that and from your prior testimony that this was a call arranged for you to walk through the key points outline and get reactions from the Commission?

A. Yeah. I think it was more to receive [96] reactions from the Commission rather than for me to walk them through.

Q. Had you had a prior call where you walked them through the key points outline?

A. I don't think so. Not that I recall.

Q. So just help me translate. So the first line DN is circled. That's Doug Nazarian?

A. Yes.

Q. Arrow. Does that say reactions?

A. Probably.

Q. And that looks like it's in quotes?

A. Yea.

Q. And then there is a series of numbered items 1 through 14, it looks like. Although I see a 15 above the 14. I'll come back to that. But a series of numbered items in any event. It may help to guide where we are in the notes. I'll just refer to the numbered items as a benchmark or milepost.

So Item No. 1.

A. Not inclined to do new stakeholder process. Get something out. See what we get.

Q. Do you recall who was doing the talking?

* * * *

[100] Q. So Item 6.

A. I think that says dispatchable capacity, separate RFP.

Q. What could that refer to, or what does that refer to?

A. I'm not sure. It may be referring to the idea that you can have separate RFPs for different products, for example, a different RFP for renewable resources.

Q. What is dispatchable capacity?

A. Dispatchable capacity usually means capacity that can be ramped up or down to fill a need. So I'm not sure why it's paired with separate RFP.

Q. Dispatchable capacity could mean like a peaking unit?

A. I'm not sure what it's referring to here.

Q. Okay. No. 7.

A. Don't waste a lot of time on FRR.

Q. Do you have an understanding why the chairman was communicating that?

MR. DAVIS: Objection.

A. I don't know why he was communicating [101] it.

Q. Is there any discussion beyond this note you recorded?

A. No, not that I recall.

Q. Why would it not make sense to waste a lot of time on FRR?

A. I'm not sure.

Q. What's your understanding of what FRR is?

A. FRR is fixed resource requirement.

It's basically a way for utilities to opt out of the RPM market by designating individual resources to serve their needs.

Q. And so is it your understanding that was not something that the chairman wanted to pursue?

MR. DAVIS: Objection.

A. I don't know what the chairman thought, but this note says for us to not waste a lot of time on it.

Q. No. 8.

A. How to manage MOPR.

Q. Did you have a discussion about how to manage MOPR?

* * * *

§ 824a. Interconnection and coordination of facilities; emergencies; transmission to foreign countries

(a) Regional districts; establishment; notice to State commissions. For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

(b) Sale or exchange of energy; establishing physical connections. Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public

utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

(c) Temporary connection and exchange of facilities during emergency. During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such

order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

(d) Temporary connection during emergency by persons without jurisdiction of Commission. During the continuance of any emergency requiring immediate action, any person engaged in the transmission or sale of electric energy and not otherwise subject to the jurisdiction of the Commission may make such temporary connections with any public utility subject to the jurisdiction of the Commission or may construct such temporary facilities for the transmission of electric energy in interstate commerce as may be necessary or appropriate to meet such emergency, and shall not become subject to the jurisdiction of the Commission by reason of such temporary connection or temporary construction: *Provided*, That such temporary connection shall be discontinued or such temporary construction removed or otherwise disposed of upon the termination of such emergency: *Provided further*, That upon approval of the Commission permanent connections for emergency use only may be made hereunder.

(e) Transmission of electric energy to foreign country. After six months from the date on which this Part [16 USCS §§ 824 et seq.] takes effect, no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the

sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.

(f) Transmission or sale at wholesale of electric energy; regulation. The ownership or operation of facilities for the transmission or sale at wholesale of electric energy which is (a) generated within a State and transmitted from that State across an international boundary and not thereafter transmitted into any other State, or (b) generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such under other provisions of this part [16 USCS §§ 824 et seq.]. The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection 202 (e) [subsec. (e) of this section].

(g) Continuance of service. In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to–

(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity

which would affect such utility's capability of serving its wholesale customers,

(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting–

(A) shortages of electric energy or capacity, and

(B) circumstances which may result in such shortages, and

(3) accommodate any such shortages or circumstances in a manner which shall–

(A) give due consideration to the public health, safety, and welfare, and

(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules. Not later than 1 year after the date of enactment of this Act [enacted Nov. 9, 1978], the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to–

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities[,] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities. The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase–

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities. The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale–

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy". For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions.

(1) Not later than 1 year after the date of enactment of this Act [enacted Nov. 9, 1978] and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 USCS §§ 791a et seq.], from the Public Utility Holding Company Act, from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act [16 USCS § 796(17)(E)]) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted

under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from–

(A) any State law or regulation in effect in a State pursuant to subsection (f),

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 USCS §§ 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 USCS §§ 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 USCS §§ 792 et seq.], any provision under such Act [16 USCS §§ 791a et seq.] related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities.

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such

rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement.

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be obtained under section 123 [16 USCS § 2633] in the case of a proceeding to which section 123 [16 USCS § 2633] applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 123 [16 USCS § 2633] with respect to an action to which section 123 applies [16 USCS § 2633].

(h) Commission enforcement.

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying

small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 USCS §§ 824 et seq.], such rule shall be treated as a rule under the Federal Power Act [16 USCS §§ 791a et seq.]. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 USCS §§ 824 et seq.].

(2) (A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act [16 USCS §§ 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act [16 USCS §§ 791a et seq.]. No enforcement action may be brought by the Commission under this section other than–

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f)[,] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not

initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts. No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after the date of the enactment of this Act [enacted Nov. 9, 1978] may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) New dams and diversions. Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act [16 USCS § 796(10)]) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:

(1) No substantial adverse effects. At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment,

including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act [16 USCS § 803] (whichever is appropriate as required by that Act or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) Protected rivers. At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) Fish and wildlife terms and conditions. The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act [16 USCS § 823a(c)].

(k) Definition of new dam or diversion. For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices)[.]

(l) Definitions. For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 USCS § 796(17) and (18)].

(m) Termination of mandatory purchase and sale requirements.

(1) Obligation to purchase. After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to–

(A) (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B) (i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

(2) Revised purchase and sale obligation for new facilities.

(A) After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

(B) For the purposes of this paragraph, the term "existing qualifying cogeneration facility" means a facility that—

(i) was a qualifying cogeneration facility on the date of enactment of subsection (m) [enacted Aug. 8, 2005]; or

(ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).

(3) Commission review. Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

(4) Reinstatement of obligation to purchase. At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon

which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) Obligation to sell. After the date of enactment of this subsection [enacted Aug. 8, 2005], no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that–

(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) No effect on existing rights and remedies. Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or nonregulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small

power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) Recovery of costs.

(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

(n) Rulemaking for new qualifying facilities.

(1) (A) Not later than 180 days after the date of enactment of this section [enacted Aug. 8, 2005], the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to section 210 of this Act [this section] to ensure–

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility,

taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.

(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to section 210 of this Act [this section]. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that–

(A) was a qualifying cogeneration facility on the date of enactment of subsection (m) [enacted Aug. 8, 2005], or

(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).

§ 824f. Ordering furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

§ 825l. Review of orders

(a) Application for rehearing; time periods; modification of order. Any person, electric utility, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this Act [16 USCS §§ 791a et seq.] to which such person, electric utility, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such application is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any orders of the Commission shall be brought by any entity unless such entity shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b), the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this Act [16 USCS §§ 791a et seq.].

(b) Judicial review. Any party to a proceeding under this Act [16 USCS §§ 791a et seq.] aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the Circuit Court of Appeals of the United States [United States Court of Appeals] for any circuit wherein the licensee or public utility to which the order relates is located or

has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the

modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in sections 239 and 240 of the Judicial Code, as amended (U. S. C., title 28, secs. 346 and 347) [28 USCS § 1254].

(c) Stay of Commission's order. The filing of an application for rehearing under subsection (a) shall not, unless specifically ordered by the Commission, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order.

§ 825m. Enforcement provisions

(a) Enjoining and restraining violations. Whenever it shall appear to the Commission that any person is engaged or about to engage in any acts or practices which constitute or will constitute a violation of the provisions of this Act [16 USCS §§ 791a et seq.], or of any rule, regulation, or order thereunder, it may in its discretion bring an action in the proper District Court of the United States, the Supreme Court of the District of Columbia [United States District Court for the District of Columbia], or the United States courts of any Territory or other place subject to the jurisdiction of the United States, to enjoin such acts or practices and to enforce compliance with this Act [16 USCS §§ 791a et seq.] or any rule, regulation, or order thereunder, and upon a proper showing a permanent or temporary injunction or decree or restraining order shall be granted without bond. The Commission may transmit such evidence as may be available concerning such acts or practices to the Attorney General, who, in his discretion, may institute the necessary criminal proceedings under this Act [16 USCS §§ 791a et seq.].

(b) Writs of mandamus. Upon application of the Commission the district courts of the United States, the Supreme Court of the District of Columbia [United States District Court for the District of Columbia], and the United States courts of any Territory or other place subject to the jurisdiction of the United States shall have jurisdiction to issue writs of mandamus commanding any person to comply with the provisions of this Act [16 USCS §§ 791a et seq.] or any rule, regulation, or order of the Commission thereunder.

(c) Employment of attorneys. The Commission may employ such attorneys as it finds necessary for proper legal aid and service of the Commission or its members in the conduct of their work, or for proper representation of the public interests in investigations made by it or cases or proceedings pending before it, whether at the Commission's own instance or upon complaint, or to appear for or represent the Commission in any case in court; and the expenses of such employment shall be paid out of the appropriation for the Commission.

(d) In any proceedings under subsection (a), the court may prohibit, conditionally or unconditionally, and permanently or for such period of time as the court determines, any individual who is engaged or has engaged in practices constituting a violation of section 221 [16 USCS § 824u] (and related rules and regulations) from–

(1) acting as an officer or director of an electric utility; or

(2) engaging in the business of purchasing or selling–

(A) electric energy; or

(B) transmission services subject to the jurisdiction of the Commission.

§ 824v. Prohibition of energy market manipulation

(a) In general. It shall be unlawful for any entity (including an entity described in section 201(f) [16 USCS § 824(f)]), directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934 (15 U.S.C. 78j(b))), in contravention of such rules and regulations as the Commission may prescribe as necessary or appropriate in the public interest or for the protection of electric ratepayers.

(b) No private right of action. Nothing in this section shall be construed to create a private right of action.

18 CFR 35.27

§ 35.27 Authority of State commissions.

Nothing in this part–

(a) Shall be construed as preempting or affecting any jurisdiction a State commission or other State authority may have under applicable State and Federal law, or

(b) Limits the authority of a State commission in accordance with State and Federal law to establish

(1) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(2) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with State law.

18 CFR 35.28

§ 35.28 Non-discriminatory open access transmission tariff.

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) Definitions.

(1) Requirements service agreement means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) Economy energy coordination agreement means a contract, or service schedule thereunder, that provides for trading of electric energy on an "if, as and when available" basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) Non-economy energy coordination agreement means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(4) Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

(5) Demand response resource means a resource capable of providing demand response.

(6) An operating reserve shortage means a period when the amount of available supply falls short of demand plus the operating reserve requirement.

(7) Market Monitoring Unit means the person or entity responsible for carrying out the market monitoring functions that the Commission has ordered Commission-approved independent system operators and regional transmission organizations to perform.

(8) Market Violation means a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff,

which tariff must be the pro forma tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of

the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the pro forma tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must

take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved.]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the pro forma tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the pro forma tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(d) Waivers. (1) A public utility subject to the requirements of this section and 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) may file a request for waiver of all or part of such requirements for good cause shown.

(2) The requirements of this section, 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) are waived for any public utility that is or becomes subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities, in whole or in part, as that term is defined in the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, or comparable jurisdictional interconnection facilities that are the subject of interconnection agreements other than the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, if the entity that owns, operates, or controls such facilities either sells electric energy, or files a statement with the Commission that it commits to comply with and be bound by the obligations and procedures applicable to electric utilities under section 210 of the Federal Power Act.

(i) The waivers referenced in this paragraph (d)(2) shall be deemed to be revoked as of the date the public utility ceases to satisfy the qualifications of this paragraph (d)(2), and may be revoked by the Commission if the Commission determines that it is in the public interest to do so. After revocation of its waivers, the

public utility must comply with the requirements that had been waived within 60 days of revocation.

(ii) Any eligible entity that seeks interconnection or transmission services with respect to the interconnection facilities for which a waiver is in effect pursuant to this paragraph (d)(2) may follow the procedures in sections 210, 211, and 212 of the Federal Power Act, 18 CFR 2.20, and 18 CFR part 36. In any proceeding pursuant to this paragraph (d)(2)(ii):

(A) The Commission will consider it to be in the public interest to grant priority rights to the owner and/or operator of interconnection facilities specified in this paragraph (d)(2) to use capacity thereon when such owner and/or operator can demonstrate that it has specific plans with milestones to use such capacity to interconnect its or its affiliate's future generation projects.

(B) For the first five years after the commercial operation date of the interconnection facilities specified in this paragraph (d)(2), the Commission will apply the rebuttable presumption that the owner and/or operator of such facilities has definitive plans to use the capacity thereon, and it is thus in the public interest to grant priority rights to the owner and/or operator of such facilities to use capacity thereon.

Note: Appendix A will not be published in the Code of Federal Regulations.

Appendix A: List of Short Names of Commenters on the Notice of Proposed Rulemaking Commenter (Short Name or Acronym)

American Public Power Association and Transmission Access Policy Study Group (APPA and TAPS)

American Wind Energy Association (AWEA)

Berkshire Hathaway Energy Company (BHE)

BP Wind Energy North America Inc. (BP Wind)

California Department of Water Resources State Water Project (SWP)

Cogen Technologies Linden Venture, L.P. (Linden)

DTE Energy Company (DTE)

Edison Electric Institute (EEI)

Electric Power Supply Association (EPSA)

Electricity Consumers Resource Council (ELCON)

E.ON Climate & Renewables North America (E.ON)

First Wind Energy, LLC (First Wind)

Invenergy Wind LLC, Invenergy Wind Development LLC, and Invenergy Thermal Development LLC (Invenergy)

ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest, LLC, and ITC Great Plains, LLC (ITC)

Midcontinent Independent System Operator, Inc. (MISO)

MISO Transmission Owners (MISO TOs)

National Rural Electric Cooperative Association (NRECA)

NextEra Energy, Inc. (NextEra)

Northern California Power Agency (NCPA)

The NRG Companies (NRG)

Recurrent Energy (Recurrent)

Sempra U.S. Gas & Power, LLC (Sempra)

Solar Energy Industries Association (SEIA)

Southern Company Services, Inc. (Southern)

Terra-Gen Dixie Valley, LLC (Terra-Gen)

(e) Non-public utility procedures for tariff reciprocity compliance. (1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the pro forma tariff.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) Standard generator interconnection procedures and agreements. (1) Every public utility that is required to have on file a non-discriminatory open

access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

(ii) – (iv) [Reserved]

(2) The non-public utility procedures for tariff reciprocity compliance described in paragraph (e) of this section are applicable to the standard interconnection procedures and agreements.

(3) A public utility subject to the requirements of this paragraph (f) may file a request for waiver of all or part of the requirements of this paragraph (f), for good cause shown.

(g) Tariffs and operations of Commission-approved independent system operators and regional transmission organizations.

(1) Demand response and pricing.

(i) Ancillary services provided by demand response resources.

(A) Every Commission-approved independent system operator or regional transmission organization that operates organized markets based on competitive bidding for energy imbalance, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services (or its functional equivalent in the Commission-approved independent system operator's or regional transmission organization's tariff) must accept bids from demand response resources in these markets for that product on a basis comparable to any other resources, if the demand response resource meets the necessary technical requirements under the tariff, and submits a bid under the Commission-approved independent system operator's or regional transmission organization's bidding rules at or below the market-clearing price, unless not permitted by the laws or regulations of the relevant electric retail regulatory authority.

(B) Each Commission-approved independent system operator or regional transmission organization must allow providers of a demand response resource to specify the following in their bids:

(1) A maximum duration in hours that the demand response resource may be dispatched;

(2) A maximum number of times that the demand response resource may be dispatched during a day; and

(3) A maximum amount of electric energy reduction that the demand response resource may be required to provide either daily or weekly.

(ii) Removal of deviation charges. A Commission-approved independent system operator or regional transmission organization with a tariff that contains a day-ahead and a real-time market may not assess a charge to a purchaser of electric energy in its day-ahead market for purchasing less power in the real-time market during a real-time market period for which the Commission-approved independent system operator or regional transmission organization declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.

(iii) Aggregation of retail customers. Each Commission-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an

aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers.

(iv) Price formation during periods of operating reserve shortage.

(A) Each Commission-approved independent system operator or regional transmission organization must modify its market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power.

(B) A Commission-approved independent system operator or regional transmission organization may phase in this modification of its market rules.

(v) Demand response compensation in energy markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff

provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) Pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) Allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

(2) Long-term power contracting in organized markets. Each Commission-approved independent system operator or regional transmission organization must provide a portion of its Web site for market participants to post offers to buy or sell power on a long-term basis.

(3) Market monitoring policies.

(i) Each Commission-approved independent system operator or regional transmission organization must modify its tariff provisions governing its Market Monitoring Unit to reflect the directives provided in Order No. 719, including the following:

(A) Each Commission-approved independent system operator or regional transmission organization must include in its tariff a provision to provide its Market Monitoring Unit access to Commission-approved independent system operator and regional transmission organization market data, resources and personnel to enable the Market Monitoring Unit to carry out its functions.

(B) The tariff provision must provide the Market Monitoring Unit complete access to the Commission-approved independent system operator's and regional transmission organization's databases of market information.

(C) The tariff provision must provide that any data created by the Market Monitoring Unit, including, but not limited to, reconfiguring of the Commission-approved independent system operator's and regional transmission organization's data, will be kept within the exclusive control of the Market Monitoring Unit.

(D) The Market Monitoring Unit must report to the Commission-approved independent system operator's or regional transmission organization's board of directors, with its management members removed, or to an independent committee of the Commission-approved independent system operator's or regional transmission organization's board of directors. A Commission-approved independent system operator or regional transmission organization that has both an internal Market Monitoring Unit and an external Market Monitoring Unit may permit the internal Market Monitoring Unit to report to management and the external Market Monitoring Unit to report to the Commission-

approved independent system operator's or regional transmission organization's board of directors with its management members removed, or to an independent committee of the Commission-approved independent system operator or regional transmission organization board of directors. If the internal market monitor is responsible for carrying out any or all of the core Market Monitoring Unit functions identified in paragraph (g)(3)(ii) of this section, the internal market monitor must report to the independent system operator's or regional transmission organization's board of directors.

(E) A Commission-approved independent system operator or regional transmission organization may not alter the reports generated by the Market Monitoring Unit, or dictate the conclusions reached by the Market Monitoring Unit.

(F) Each Commission-approved independent system operator or regional transmission organization must consolidate the core Market Monitoring Unit provisions into one section of its tariff. Each independent system operator or regional transmission organization must include a mission statement in the introduction to the Market Monitoring Unit provisions that identifies the Market Monitoring Unit's goals, including the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses.

(ii) Core Functions of Market Monitoring Unit. The Market Monitoring Unit must perform the following core functions:

(A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-approved independent system operator or regional transmission organization, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants, provided that:

(1) The Market Monitoring Unit is not to effectuate its proposed market design itself, and

(2) The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to Commission staff in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) Review and report on the performance of the wholesale markets to the Commission-approved independent system operator or regional transmission organization, the Commission, and other interested entities such as state commissions and market participants, on at least a quarterly basis and submit a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

(C) Identify and notify the Commission's Office of Enforcement staff of instances in which a market participant's or the Commission-approved independent system operator's or regional transmission organization's behavior may require

investigation, including, but not limited to, suspected Market Violations.

(iii) Tariff administration and mitigation

(A) A Commission-approved independent system operator or regional transmission organization may not permit its Market Monitoring Unit, whether internal or external, to participate in the administration of the Commission-approved independent system operator's or regional transmission organization's tariff or, except as provided in paragraph (g)(3)(iii)(D) of this section, to conduct prospective mitigation.

(B) A Commission-approved independent system operator or regional transmission organization may permit its Market Monitoring Unit to provide the inputs required for the Commission-approved independent system operator or regional transmission organization to conduct prospective mitigation, including, but not limited to, reference levels, identification of system constraints, and cost calculations.

(C) A Commission-approved independent system operator or regional transmission organization may allow its Market Monitoring Unit to conduct retrospective mitigation.

(D) A Commission-approved independent system operator or regional transmission organization with a hybrid Market Monitoring Unit structure may permit its internal market monitor to conduct prospective and/or retrospective mitigation, in which case it must assign to its external market monitor the responsibility and the tools to monitor the quality and appropriateness of the mitigation.

(E) Each Commission-approved independent system operator or regional transmission organization must identify in its tariff the functions the Market Monitoring Unit will perform and the functions the Commission-approved independent system operator or regional transmission organization will perform.

(iv) Protocols on Market Monitoring Unit referrals to the Commission of suspected violations.

(A) A Market Monitoring Unit is to make a non-public referral to the Commission in all instances where the Market Monitoring Unit has reason to believe that a Market Violation has occurred. While the Market Monitoring Unit need not be able to prove that a Market Violation has occurred, the Market Monitoring Unit is to provide sufficient credible information to warrant further investigation by the Commission. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Market Monitoring Unit from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Market Monitoring Unit is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) The name[s] of and, if possible, the contact information for, the entity[ies] that allegedly took the action[s] that constituted the alleged Market Violation[s];

(2) The date[s] or time period during which the alleged Market Violation[s] occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act[s] or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Market Monitoring Unit believes that the act[s] or conduct constituted a violation of the anti-manipulation rule of Part 1c, a description of

the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any information that the Market Monitoring Unit learns of that may be related to the referral, but the Market Monitoring Unit is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission Staff.

(v) Protocols on Market Monitoring Unit Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) A Market Monitoring Unit is to make a referral to the Commission in all instances where the Market Monitoring Unit has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw[s];

(2) The consequences of the perceived market design flaw[s], including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Market Monitoring Unit believes could remedy the perceived market design flaw;

(4) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Market Monitoring

Unit to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

(vi) Market Monitoring Unit ethics standards. Each Commission-approved independent system operator or regional transmission organization must include in its tariff ethical standards for its Market Monitoring Unit and the employees of its Market Monitoring Unit. At a minimum, the ethics standards must include the following requirements:

(A) The Market Monitoring Unit and its employees must have no material affiliation with any market participant or affiliate.

(B) The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a market participant.

(C) The Market Monitoring Unit and its employees must have no material financial interest in any market participant or affiliate with potential exceptions for mutual funds and non-directed investments.

(D) The Market Monitoring Unit and its employees must not engage in any market transactions other than the performance of their duties under the tariff.

(E) The Market Monitoring Unit and its employees must not be compensated, other than by the Commission-approved independent system

operator or regional transmission organization that retains or employs it, for any expert witness testimony or other commercial services, either to the Commission-approved independent system operator or regional transmission organization or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the Commission-approved independent system operator or regional transmission organization or to the Commission-approved independent system operator's or regional transmission organization's markets.

(F) The Market Monitoring Unit and its employees may not accept anything of value from a market participant in excess of a de minimis amount.

(G) The Market Monitoring Unit and its employees must advise a supervisor in the event they seek employment with a market participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the market participant.

(4) Electronic delivery of data. Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

(5) Offer and bid data. (i) Unless a Commission-approved independent system operator or regional transmission organization obtains Commission

approval for a different period, each Commission-approved independent system operator and regional transmission organization must release its offer and bid data within three months.

(ii) A Commission-approved independent system operator or regional transmission organization must mask the identity of market participants when releasing offer and bid data. The Commission-approved independent system operators and regional transmission organization may propose a time period for eventual unmasking.

(6) Responsiveness of Commission-approved independent system operators and regional transmission organizations. Each Commission-approved independent system operator or regional transmission organization must adopt business practices and procedures that achieve Commission-approved independent system operator and regional transmission organization board of directors' responsiveness to customers and other stakeholders and satisfy the following criteria:

(i) Inclusiveness. The business practices and procedures must ensure that any customer or other stakeholder affected by the operation of the Commission-approved independent system operator or regional transmission organization, or its representative, is permitted to communicate the customer's or other stakeholder's views to the independent system operator's or regional transmission organization's board of directors;

(ii) Fairness in balancing diverse interests. The business practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered, and that deliberation and consideration of Commission-approved independent system operator's and regional transmission organization's issues are not dominated by any single stakeholder category;

(iii) Representation of minority positions. The business practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the Commission-approved independent system operator's and regional transmission organization's board of directors at the same time as majority positions; and

(iv) Ongoing responsiveness. The business practices and procedures must provide for stakeholder input into the Commission-approved independent system operator's or regional transmission organization's decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

(7) Compliance filings. All Commission-approved independent system operators and regional transmission organizations must make a compliance filing with the Commission as described in Order No. 719 under the following schedule:

(i) The compliance filing addressing the accepting of bids from demand response resources in markets for ancillary services on a basis comparable to other resources, removal of deviation charges, aggregation of retail customers, shortage pricing during periods of operating reserve shortage, long-term power contracting in organized markets, Market Monitoring Units, Commission-approved independent system operators' and regional transmission organizations' board of directors' responsiveness, and reporting on the study of the need for further reforms to remove barriers to comparable treatment of demand response resources must be submitted on or before April 28, 2009.

(ii) A public utility that is approved as a regional transmission organization under § 35.34, or that is not approved but begins to operate regional markets for electric energy or ancillary services after December 29, 2008, must comply with Order No. 719 and the provisions of paragraphs (g)(1) through (g)(5) of this section before beginning operations.

(8) Frequency regulation compensation in ancillary services markets. Each Commission-approved independent system operator or regional transmission organization that has a tariff that provides for the compensation for frequency regulation service must provide such compensation based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.